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National Electricity Code

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Commissioners:
Fels
Asher
Shogren
Smith
Bhojani
Lieberman
Johns
Reeves

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Glossary

ABARE	Australian Bureau of Agricultural and Resource Economics
ACA	Australian Cogeneration Association
ACCI	Australian Chamber of Commerce and Industry
ACM	Australian Chamber of Manufactures
ACTEW	ACT Electricity and Water
AGA	Australian Gas Association
AGL	Australian Gas Light Company
BCA	Business Council of Australia
BCA/EWG	Business Council of Australia Energy Working Group
BIE	Bureau of Industry Economics
CAPM	Capital Asset Pricing Model
CCP	Code Change Panel
CFA	Consumers' Federation of Australia
COAG	Council of Australian Governments
CSO	Community Service Obligation
DBs	Distribution Businesses
DNSP	Distribution Network Service Provider
DPIE	Department of Primary Industries and Energy (Commonwealth)
DRP	Dispute Resolution Panel
DUOS	Distribution Use of System
EI Act	Electricity Industry Act 1993 (Victoria)
EIS	Environment Impact Statement
EME	Edison Mission Energy
ERTF	New South Wales Electricity Reform Taskforce
ESI	Electricity Supply Industry
ETSA	Electricity Trust of South Australia
EUG	Energy Users Group
EWN	Electricity Week Publishers
Gwh	Gigawatt per hour
IC	Industry Commission
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRFM	Industrial Relations Force Majeure
IRH	Inter-regional Hedge
IRPC	Inter-regional Planning Committee
LYB	Loy Yang B
MW	Megawatt
MWh	Megawatt per hour
NCC	National Competition Council
NEC	National Electricity Code

NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMNET	National Electricity Market Network
NEM1	National Electricity Market Stage 1
NEMMCO	National Electricity Market Management Company
NERA	National Economic Research Associates
NFF	National Farmers Federation
NGMC	National Grid Management Council
NSP	Network Service Provider
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimal Deprival Value
ORG	Office of the Regulator–General, Victoria
PASA	Projected Assessment of Systems Adequacy
PCF	Participant Compensation Fund
PHB	Putnam, Hayes and Bartlett
PNV	PowerNet Victoria
QERU	Queensland Electricity Reform Unit
QNI	Queensland — New South Wales Interconnector
QTC	Queensland Treasury Corporation
SECV	State Electricity Commission of Victoria
SEQEB	South East Queensland Electricity Board
SHT	Snowy Hydro Trading
SMHEA	Snowy Mountains Hydro-Electric Authority
SRA	Smelter Reduction Amount
STFM	Short Term Forward Market
TPA	Trade Practices Act 1974
TUOS	Transmission Use of System
VoLL	Value of Lost Load
VPX	Victorian Power Exchange
WACC	Weighted Average Cost of Capital

Overview of the National Electricity Code determination

1. Introduction

On 15 November 1996, the Australian Competition and Consumer Commission (the Commission) received applications for authorisation of the National Electricity Code (the Code). The applications were submitted under Part VII of the *Trade Practices Act 1974* (the TPA) and, together with the supporting submissions were lodged by the National Electricity Market Management Company (NEMMCO) and the National Electricity Code Administrator (NECA). Amendments to these applications were received on 28 April 1997 and 23 July 1997.

Authorisation under Part VII of the TPA provides immunity from court action for 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 has prepared a *Determination* outlining its analysis and views on the key competitive issues in relation to the applications for authorisation of the Code. In assessing the Code, according to its statutory criteria, the Commission believes that despite structural and administrative reform to the electricity industry at the jurisdictional level, the full realisation of the benefits of reform depends upon implementing national electricity market and access arrangements through the Code. This is because the national arrangements have efficiency benefits in terms of better utilisation of infrastructure and capital than allowed for in the current State based regimes, as well as giving rise to efficiency benefits from transparent and uniform treatment of wholesale participants across the interconnected grid.

However, the Commission's assessment of the Code has identified a number of shortcomings which will influence the effectiveness of competition and hence impact on the balance between public benefit and anti-competitive detriment. Some of these shortcomings involve complex issues and will take time to resolve. Other shortcomings can be handled easily through the normal Code change process. Some of the issues raised in the *Determination* go beyond the subject matter of the Code and the scope of the applicants' responsibilities. The Commission's purpose in raising them is to highlight their implications for the effectiveness of competition in the national electricity market (NEM) and the efficiency of the market outcomes that are likely to result.

This *Overview of the National Electricity Code Determination* provides a summary of the Commission's assessment of the Code. It also lists the amendments to the Code that the Commission requires as a condition of authorisation.

On 28 April 1997 the Commission received an application from NECA to accept the Code, under Part IIIA of the TPA, as an industry access Code for electricity transmission and distribution facilities in the participating jurisdictions. The Commission's assessment of the access Code is the subject of a separate determination which is being finalised by the Commission. A draft of the determination the *NEM Access Code Draft Determination*, was published on 29 August 1997.

1.1 Overview of the National Electricity Code

Australian governments have initiated fundamental reforms to improve the performance of the electricity supply industry (ESI).[1] To varying degrees the State and Territory governments have restructured, corporatised and even privatised previously vertically integrated public monopolies.

In a process co-ordinated through the Council of Australian Governments (COAG), the relevant jurisdictions (New South Wales, Victoria, Queensland, South Australia, and the Australian Capital Territory) have also moved to create a 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 is a lengthy and complex document encompassing a comprehensive range of reforms. It comprises two distinct but inter-related elements:

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

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

The access arrangements are the rules governing connection to and use of the physical wires infrastructure for transporting electricity. The access and market arrangements also stipulate detailed outcomes in terms of technical standards and requirements to preserve system security.

Further, the Code includes derogations to allow some jurisdictional based arrangements, which depart from the requirements of the Code, to continue either over a transitional period or indefinitely. 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 (NEL), 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 national market arrangements contained in the Code will commence in March 1998, subject to the conditions imposed by the Commission. In the interim, harmonisation of the State and Territory arrangements in New South Wales, Victoria and the Australian Capital Territory, known as NEM1, are expected to continue. The other NEM participating jurisdictions, Queensland and South Australia, are in the process of structural and regulatory reform in the lead up to the NEM. An interim state market commenced in Queensland on 1 October 1997. The market arrangements are based on the NEM proposals.

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[1] The electricity supply industry is a generic term which encompasses the production, distribution and sale of electricity to the final consumer.

2. The importance of electricity supply industry reform

The importance of reform in the ESI is underscored by the significant role it plays in the Australian economy, as well as by the size of the potential benefits that are likely to accrue from the successful implementation of reforms.

As an infrastructure industry the ESI ranks third in terms of its contribution to GDP (2.2 per cent in 1994–95) behind communications and road transport. In 1994–95 the industry raised $12.3 billion from electricity sales, employed approximately 42 000 persons and controlled capital assets worth $43 billion.[2] Electricity provides an important input into all Australian industry influencing the ability of firms to compete both domestically and internationally. On average electricity comprises 0.3 to six per cent of industry costs (considerably more for energy intensive industries like smelting and non-ferrous metals),[3] and in total represents 18 per cent of Australia's energy needs.[4]

The successful introduction of competitive reforms to the ESI is a key to providing strong incentives to participants to improve the efficiency of their production, resource allocation and investment decisions, and to minimise costs. The benefits flowing from competitive reforms are likely to be distributed broadly throughout the economy, through lower input prices to Australian industry, lower prices to end use consumers, and more efficient use of society's resources.

Estimates indicate that the benefits of electricity reform are likely to be substantial, in the order of $5.8 billion (in 1993–94 dollars) or 1.4 per cent of gross national income.[5] Significant reforms at the jurisdictional level mean that some of these benefits have already been realised through corporatisation, industry restructuring, privatisation and the development of State based trading arrangements. However, the development of an interconnected national market will generate further significant benefits, complement other reforms and will have a bearing on whether the benefits of reform are passed on to users and the community.

2.1 The specific benefits of interconnection, structural reform and wholesale market competition

Despite the significant structural and administrative reform in the States, the full benefits of reform require the implementation of a national market. There are four main sources of economic benefit from an interconnected wholesale market that can be identified.

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2 BIE (Bureau of Industry Economics), *Electricity 1996, International Benchmarking*, Australian Government Publishing Service, Canberra, 1996.

3 BIE, *Electricity 1996, International Benchmarking*, Australian Government Publishing Service, Canberra, 1996. Table A1.6.

4 ABARE (Australian Bureau of Agriculture and Resource Economics), *Energy, Australian Energy Consumption and Production, Historical Trends and Projections to 2009–10,* Canberra, 1997.

5 This benefit was the largest single benefit in the overall Hilmer and related reforms estimated by the IC (Industry Commission, *The Growth and Revenue Implications of Hilmer and Related Reforms: A report by the Industry Commission to the Council of Australian Governments (Final Report)* Australian Government Publishing Service, Canberra, March 1995). Although the share of the $5.8 billion benefit associated with electricity reform was not explicitly specified by the IC, an earlier IC report (Industry Commission, *Energy Generation and Distribution*, Vol 2: Report, No. 11, 17 May 1991) suggested that over 90 per cent of combined electricity and gas reform benefits could be attributed to electricity reform.

First, economic benefits can arise from greater competition between suppliers made possible by a larger interconnected network. Under the NEM arrangements dispatch of scheduled generating units and loads is to be determined through a competitive auction process where generating units and loads are dispatched nationally in least cost merit order, subject to any physical constraints placed on dispatch by the power system. It is argued by the applicants that bidding in this manner, in conjunction with demand responses, will clear the market and reflect the differing economic cost of electricity over different time periods and with respect to different technologies.

Second, the development of market based incentives via national arrangements can improve the efficiency of resource allocation. An industry which faces market prices for its input and market rates for its capital, while facing market censure for poor use of such inputs, is likely to allocate inputs far more effectively than if price signals are not present. In this environment the costs of poor production and investment decisions will no longer be borne by consumers through higher prices and poorer service/product options. The costs of inefficient investment and production decisions will be borne by shareholders in the form of lower share prices or firm financial performance. In the case of publicly owned businesses, poor performance is likely to increase the pressure for governments to reassess their ownership of such businesses. In short, efficiency gains will result from pressures on electricity producers to reduce costs, align tariffs and prices with costs, and use their assets more effectively.

Third, benefits can be derived from the deferral of new plant investment. To maintain power supply, electricity authorities need to have excess capacity (reserve plant) to provide for both foreseen and unforseen generator downtime. The development of State based industries resulted in each State maintaining a high reserve margin for plant. Interconnection of State grids has the potential to reduce reserve plant margins by sharing between jurisdictions better management of non-coincident peaks. Surplus capacity in one area can be used to supplement local generation in another area, or to provide reserve in other areas. Lowering the levels of reserve will imply benefits for both producers and consumers through reduced total capital requirements.

Fourth, benefits will arise from complementarities between State systems. Electric power is difficult to store and demand is highly variable. Some electricity production methods, such as hydro-electric generation can respond quickly to changes in demand, others such as thermal coal stations, although slower in response, are relatively cheaper for base load supplies. Interconnection between systems based on different technologies can make better use of existing generating capabilities and therefore increase flexibility and reduce costs.

2.3 What will limit the benefits of reform?

The benefits of reform arising from the implementation of national arrangements are to be realised through each of the structural levels of the ESI, that is through:

- the introduction of competition in the wholesale market;
- access to the transmission and distribution networks, along with the effective regulation of network monopolies; and
- the facilitation of retail competition.

The Commission accepts that the Code arrangements have the potential to result in greater efficiencies in the ESI, lower input costs for other industries, lower prices and provide better service delivery to end users. However, the Commission also recognises that there are features of the Code and factors external to the Code that could offset, perhaps to a significant extent, these anticipated public benefits.

To the extent that competition in the upstream (generation) and downstream (retail) markets is insufficient, or regulation and access to the infrastructure elements is weak, the benefits arising from reform will not be passed through to final consumers and, given that the ESI is an infrastructure industry, the economic consequences will impact upon the whole economy.

The following discussion examines each of the structural levels of the ESI and identifies elements of the wholesale trading arrangements, the access and network pricing regime and retail arrangements that may limit or negate the benefits from reforms.

3. Factors limiting the public benefits from the wholesale market arrangements

The ability of the wholesale arrangements to deliver benefits is dependent on two features: the industry structure established in participating jurisdictions and the Code's design and implementation. These two features will have important implications for the development of effective wholesale competition in the NEM and consequently for the public benefits stemming from reforms.

3.1 Market structure

Analysis of the structure of the NEM by the Commission's consultants, the Australian Bureau of Agricultural and Resource Economics (ABARE), indicates that the NEM is characterised by a significant degree of market concentration, particularly in South Australia and New South Wales.

ABARE found that the current market structure is such that large generation portfolios in South Australia and New South Wales would be in a position to dominate particular segments of the market. This occurs because in periods where the level of demand is high relative to the capacity of rival generators, an individual generator may face a residual demand and hence be in a position to bid 'strategically' to maximise profits. By contrast, in low demand periods when the combined capacity of rival generators is greater than demand no single supplier faces a residual market, and competitive pricing is likely to result as generators compete for a share of the limited market.

ABARE's modelling results indicate that such strategic bidding behaviour during periods of high demand could lead to significant increases in electricity spot prices. All generators in the NEM are estimated to benefit from the higher operating surpluses resulting from strategic behaviour by major players. Therefore, according to ABARE large generation portfolios in New South Wales and South Australia would have strong incentives to bid strategically.

ABARE notes that regulation and entry can provide a check on the exercise of market power. However, it suggests that structural reform such as further disaggregation of generation assets may be necessary, not only to reduce the need for regulatory intervention, but also to ensure that the competitive benefits from the implementation of the NEM are attained. Establishing more generation businesses to compete in the market should make it more difficult to exercise market power as it results in capacity demanded being distributed among a number of competing businesses. This means that it becomes much riskier for any one generator to assume that it will be the marginal producer, forcing it to bid into the pool at marginal cost to ensure dispatch. Competitive pressures will be increased if there is a significant influx of new entrants to generation. The likelihood, and extent, of this depends crucially on the ease of entry, perceptions about future electricity prices and the behaviour of incumbent generators. There is considerable uncertainty about the latter two matters at present, as assessments of price outcomes are clouded by the surplus of generating capacity.

The Commission appreciates that in the context of the initial reforms of the ESI market structure is a matter for the individual jurisdictions. However, international evidence, coupled with the ABARE analysis is sufficient to alert the Commission to the substantial detriment to the public from the potential manipulation of pool prices arising from a concentrated market structure. The Commission therefore strongly urges participating jurisdictions to examine the structure of their generation sectors, with a view to restructuring to minimise the potential for generation businesses to exercise market power, and hence reduce or negate the public benefits of the NEM reforms. In particular the South Australian Government is urged to consider effective regulation of generation in that State. Similarly, the New South Wales Government is urged to consider the further disaggregation of its portfolio generators.

The Commission notes that the issue of market structure is not only crucial at the commencement of the NEM but will be of on-going interest, particularly in respect of possible re-integration of participating firms. The Commission's concerns include possible mergers within each segment of the market and also arrangements whereby NEM participants operate in upstream or downstream sectors (such as a generation company also operating a retailing business). In this regard the Commission is responsible for assessing whether a merger or acquisition results, or is likely to result in a substantial lessening of competition in the relevant market or markets pursuant to s. 50 of the TPA.

3.2 Features of the Code that will limit the benefits derivable from the wholesale market arrangements

In examining the Code for the purposes of this authorisation the Commission has identified a number of shortcomings. The following analysis details key sections of the Code with which the Commission has concerns in terms of achieving future public benefit. A complete discussion is contained in the Commission's *Determination*.

Market distortions arising from the Code

There are a number of elements in the Code which have the potential to create market distortions either by preventing market solutions from being developed or constraining the domain within which the market will operate. These distortions may impact on spot market outcomes and investment decisions because such outcomes may be substantially different to outcomes produced by a competitive market.

The applicants' primary rationale for proposing Code rules which override market outcomes is the current lack of market maturity. Market immaturity, it is claimed, is partially manifested in the inability of the demand side to respond to price and the supply side's lack of experience with operating in a wholesale national market. This, it is claimed, means that some provisions are required to assist in maintaining the market during an initial learning phase.

The inherent danger in allowing these distortions is that they may become entrenched, and participants will be reluctant to see their removal. A further risk is that these provisions will prevent alternative market based solutions from developing. The Commission's assessment of the Code has identified:

- the price cap;
- the floor price; and
- the following NEMMCO functions:
  - short term forward market;
  - ancillary services;
  - inter-regional hedging arrangements; and
  - reserve trader

as provisions that have been incorporated into the Code to address market immaturity. In addition, aspects of NEMMCO's system security role and capacity to override the market to maintain security of supply could also undermine the development of a mature market.

The price cap (which is currently set at $5000, and is a protected provision)[6] places an upper bound on the spot price, and hence the revenues that a seller in the market may earn. A high spot price provides a key market signal for long term investment in reserve. If the level of the price cap is set too low it will materially impact on capacity available to the market due to its influence on the return on marginal plant or load. Hence the Commission has determined that for as long as the price cap is to remain it is vital that it be reviewed annually.

The floor price will apply during periods of excess generation. The applicants have not put forward any satisfactory economic arguments for the floor price to remain. Thus, as a condition of authorisation, the floor price must be removed one year after market commencement. Further, while the floor price remains money accumulated during excess generation periods must be returned to market customers by a method to be determined by NEMMCO.

The Commission does not doubt the importance of financial instruments for managing risk and the development of an integrated market under the Code. Developments to date in the New South Wales and Victorian wholesale markets indicate that participants have developed financial instruments to meet their short term hedging requirements, without any central facilitation. For this reason the Commission makes it a condition of authorisation that the clauses referring to NEMMCO's role in operating or facilitating the short term forward market (STFM) be removed.

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[6] Under the NEL a protected provision may not be amended except with the unanimous approval of the Ministers of *all* participating jurisdictions. The Commission has imposed a condition of authorisation removing the protected provision status of the price cap, see condition of authorisation C6.3.

The experience of New South Wales and Victoria provides an important lesson in the versatility of markets to respond to the needs of buyers and sellers, a lesson which can be applied to other Code provisions currently justified on perceived market immaturity grounds.

Similarly, with respect to the Code provisions on inter-regional hedges (IRHs), it is evident that financial intermediaries are assisting wholesale participants in the New South Wales and Victorian markets to manage inter-regional risk, without central facilitation. In assessing the Code's provisions the Commission is not convinced that they provide a least cost solution to the possible need for centralised intervention. The Commission therefore makes it a condition of authorisation that all clauses relating to inter-regional hedging be removed.

However, the Commission does appreciate that the absence of transporters as natural providers of IRHs may mean that some form of managed solution is needed to ensure IRHs are made available to the market in sufficient volume and at such prices that enable the full benefits of a NEM to be achieved. Also, given the novel nature of IRHs there may be some justification for facilitating the emergence of trading forums, but any such facilitation should be strictly limited to the minimum necessary in order to encourage independent initiatives. Accordingly, the Commission recommends that the applicants develop and implement a proposal for a facilitated IRH regime within three months after the end of the NECA transmission pricing review.

The applicants argue that the market is too immature to properly manage system security and therefore central co-ordination of reserve and central provision of ancillary services by NEMMCO is necessary. While there may be an argument for central provision of such services, the Commission is concerned that either premature intervention or intervention over the longer term could mute the development of market signals. Participants may become complacent, believing they will be sheltered from supply shortages and the associated high spot prices and be less inclined to develop market solutions to manage their risk.

While adequate arrangements for maintaining power system security are in the public interest it is also important that these arrangements are efficient. Opening the supply of ancillary services to competition and using market mechanisms to supply reserve capacity and provide load shedding capabilities are ways to reduce the costs of providing a secure power system. However, achieving an appropriate balance between market mechanisms and intervention will not be straightforward. This is because the market is evolving from a set of arrangements whereby system security was provided by publicly owned utilities and where market forces were muted. Nevertheless, there appears to be considerable scope to use market mechanisms to deliver some ancillary services and reserve.

Consequently the Commission has imposed as a condition of authorisation that the reserve trading function must end on 30 June 2000. The Commission believes that the provision in the Code to allow the reserve trader to remain for five years underestimates the ability of the market to develop mechanisms to deal with reserve shortages.

The Commission is aware of developments to establish a market for ancillary services prior to the commencement of the NEM. The Commission requires that the Code provide for NEMMCO to report to NECA on the viability of market provision of ancillary services within one year of market commencement.

The Commission appreciates market responses cannot be expected to be sufficient in all circumstances. In responding to such concerns and in emergency circumstances, it will be important to ensure administrative interventions do not crowd-out market responses. Thus, the rules for intervention need to be closely specified in order to encourage a market response. The aim of the Commission's conditions of authorisation is to make intervention more transparent.

In summary, the Commission notes the market immaturity argument but has reservations regarding its strength. While there may be some limited need to facilitate the development of market arrangements, these must be restricted in both time and scope in order to encourage the market to develop its own solutions. NEM participants should expect that central provision of services will cease. Accordingly it is a condition of the authorisation being granted that these identified Code provisions be amended and/or removed within the timeframes set down in the *Determination*.

Market monitoring

The Code provides for an extensive range of information gathering and dissemination requirements.

According to the applicants the nature of electricity supply and demand means that market efficiency requires a high level of information disclosure. They argue that prohibiting or limiting the extent of detailed release of information could create information asymmetries as larger players have the resources to derive the information they require. Thus, restricting information disclosure may only disadvantage smaller players. In addition, the applicants and interested parties feel that the immediate dissemination of at least some information could serve the purpose of economic efficiency.

However, the Commission is not entirely convinced by such reasoning. There are powerful arguments for limiting the degree of information sharing or dissemination between firms in a market such as the NEM which is characterised by a limited number of participants and which is designed as a repeated auction. With such detailed information provided for under the Code, participants will be able to observe the competitive strategies and monitor the economic progress of rivals. Hence the Commission is concerned that the potential for anti-competitive behaviour or strategic or oligopolistic behaviour may be made easier by the availability of such immediate and detailed information on competitors. The Commission also notes that this potential is increased by the rebidding arrangements set out in the Code.

However, the Commission has decided that it will allow the Code provisions for information disclosure and rebidding, as presently drafted, to remain subject to strict monitoring and review. The Commission makes it a condition of authorisation that the Code be amended to require that NECA monitor market outcomes, and provide quarterly reports on the market outcomes to the Commission, and publicly.

In addition, based on the argument for transparency and market self policing, the Commission sees no reason why certain information should be restricted to those within the industry. Therefore the Commission requires that the Code be altered to explicitly allow information available to Code participants to be available to non-Code participants on a non-differentiated, cost reflective basis.

Derogations

Derogations have been included largely to provide a transitional mechanism whereby different jurisdictional arrangements can be harmonised over a period of time, and to meet existing contractual obligations. Where derogations exist the Code provisions are replaced by the existing arrangements and jurisdictional based access regimes. These arrangements can provide an orderly transitional path to the commencement of uniform NEM requirements.

In addition to short term transitional arrangements, there are some derogations which extend well beyond the year 2000 (e.g. the Victorian equalisation payments which phase out by 30 June 2020). Given the duration of these derogations they are clearly a more permanent deviation from nationally consistent arrangements.

Further, there are other derogations which are permanent and not part of a transitional path. The Commission will not accept these derogations as they are likely to impact adversely on the public benefit. For example, the Commission understands the rationale associated with avoiding expensive upgrades to generators and other facilities simply to comply with the Code's technical requirements with possibly little, if any, appreciable benefit to system performance. However, the Commission is concerned that entry barriers could be created by grandfathering existing facilities while requiring new facilities to meet Code requirements. Consequently, at this time, the Commission will not accept any technical derogations which apply beyond 31 December 2002.

The Commission has a substantial concern in relation to the South Australian and the Victorian transmission pricing derogations. While such derogations may possibly be construed to be in the public interest on the basis of social welfare and State development concerns, the Commission believes that a uniform approach to the regulation of transmission networks will be central to the effective development of a fully integrated electricity market in southern and eastern Australia. Indeed, the various jurisdictions have devoted considerable time to developing the Code in order to achieve uniformity and it would be disappointing to see such efforts wasted.

Consequently, the Commission makes it a condition of authorisation that the South Australian transmission pricing derogations must end by 31 December 2002 or earlier.

The Victorian transmission pricing derogation has been justified on a number of grounds, including that it will give the transmission asset owner regulatory certainty, and create better incentives to implement efficiencies as the asset owner will be able to retain the benefits of efficiencies irrespective of their timing. However, it is not evident to the Commission that the proposed arrangements provide greater incentives to implement efficiencies and investment than other regulatory arrangements. In addition the prescriptiveness of the arrangements severely limits the flexibility of the transmission regulator in the application of price regulation methodology, without offering any sort of guarantee as to the benefits to consumers from the arrangements. The Commission makes it a condition of authorisation that the Victoria derogation regarding transmission pricing end by 31 December 2002 or earlier.

Other issues

Apart from the significant concerns discussed above, the Commission has also identified a range of other shortcomings which impinge on the public benefit achievable from implementation of the Code. For instance, of particular concern are those provisions of the Code that potentially represent a barrier to entry. In this regard the Commission has identified deficiencies in the prudential requirements which must be addressed prior to market commencement. In addition the Commission has also identified shortcomings with the metering provisions which may diminish retail contestability.

A full list of conditions is contained in section 7 of this O*verview* and the Commission's detailed analysis can be found in the *Determination*.

4. Factors limiting the achievement of public benefit from the access arrangements

The transmission and distribution networks are considered to be natural monopolies and owners of such infrastructure have the opportunity to engage in a number of practices that could prevent competitive outcomes. The extent to which the Code's access arrangements are ineffective could lead to efficiencies achieved in upstream reform being captured, and competition downstream being reduced, and the network owner obtaining monopoly profits.

In assessing the Code's access regime the Commission believes that the arrangements act in the interests of both network service providers (NSPs) and users in retaining sufficient flexibility to allow negotiated connection agreements to be tailored to meet the demands of specific connection proposals. In addition, these negotiation procedures are subject to certain time lines and dispute resolution procedures.

Despite this, for the purposes of authorisation and for its effectiveness as an access regime, the Commission has identified a number of shortcomings in the Code which significantly impact on the public benefits.

Independence of the jurisdictional regulator from government

In most circumstances the regulator is required to act in the public interest. However, this may not always be the case, and conflicts of interest may arise when a government is both the regulator and owner of electricity assets. These potential conflicts of interest will be most acute in circumstances where the regulator is not at arms length from government and where government budgets have come to rely on the dividend stream from publicly owned utilities.

Already the majority of the participating jurisdictions have established, or are considering establishing, independent regulators for electricity network pricing. However, at the time of making this authorisation determination, the issue of independence of jurisdictional regulators has yet to be fully resolved. Thus the Commission considers that the jurisdictional regulators should be statutorily independent of executive government by the time of the commencement of the NEM's network pricing regimes in 1999.

Improving locational signals and network pricing

The Commission is of the view that network pricing and regulation proposals should be designed to:

- prevent monopoly rent taking by transmission network owners; and
- provide effective market price signals for the use of existing network facilities and for future investment in the network.

Ideally the pricing structure should provide price signals which reflect the extent of congestion or spare capacity at different points of the network and so influence the pattern of demand for network services. It should also provide efficient signals for investment in augmentation of congested parts of the network. The Commission has concerns that there may be shortcomings in the transmission pricing and regulatory methodology of the Code and the Code may not reflect adequately emerging international experience on network pricing.

In particular the Commission is concerned that the current Code proposal, whereby the great proportion of network charges will be levied on customers, provides little incentive for the efficient location of investment in network or generation options. Locating generation facilities close to load can lead to significant network savings, but if the network charges do not enable the owners of generation assets to realise the benefits of locating close to load (i.e. savings on network charges), the incentives for investment decisions are lost or muted. As generators compete on a delivered cost basis, this incidence of network charges disadvantages embedded generation options. Nevertheless, the Code recognises this deficiency and encompasses limited options to overcome this and other deficiencies in the network pricing regime (i.e. payments from distributors to embedded generators).

The Commission is concerned that these deficiencies in the Code may be contrary to the interests of embedded generators, thereby impacting on the anti-competitive detriment of the NEM arrangements. The Commission does not want to pre-judge the outcome of the NECA transmission pricing review, but requires that the Code must, in the interim, encompass some remedy to introduce additional locational signals. Mechanisms similar to those adopted by the Independent Pricing and Regulatory Tribunal (IPART) in New South Wales appear to provide some relief for embedded generators while maintaining the proposed incidence of network use of system charges. NECA has accepted the Commission's position and will re-examine the efficiency of network charges as part of its review and will include in the Code (as an interim measure) arrangements for embedded generators to negotiate for the pass through of any savings in transmission charges.

Given the role embedded generators could play as new entrants to the NEM, and the public benefits they can provide in terms of reducing the need for network augmentation, the Commission has secured NECA's agreement to consider the unbundling of transmission and distribution use of system charges as part of the NECA review.

The right to bypass existing networks

The Code is silent on the right to bypass a network. Without an explicit right to bypass a network, access seekers have very little bargaining power in a negotiation process with a network monopoly. For instance, without a guaranteed right to bypass, a NSP is unlikely to view as credible an access seeker's threat to withdraw from negotiations to seek alternative network arrangements.

The applicants indicate that the Code permits bypass without encouraging or discouraging it. The applicants state that this approach was adopted to ensure that bypass of the existing networks only occurs when it is the least cost option from a total societal perspective. They also argue mandating bypass is unnecessary as it would always be in the interests of NSPs to encourage new connections because of the additional revenue.

There appears to be a strong basis to the interested party's arguments that without an explicit right to bypass a network, access seekers have very little bargaining power in a negotiation process with a network monopoly. Indeed, without a bypass option the NSP could be viewed as possessing an exclusive franchise. This is clearly inconsistent with the Code's principles of contestable network facilities. It is also inconsistent with the bypass arrangements for gas pipelines in the proposed national gas code arrangements. Consequently, as a condition of authorisation the Commission requires that the Code include an explicit right to bypass electricity networks.

5. Factors limiting the achievement of public benefit at the retail level

Retail competition is not covered by the Code and is to be the subject of jurisdictional regulation. Effective retail competition is vital to the delivery of public benefits from ESI reforms to end use consumers. Therefore the Commission views retail competition as an important market reform issue which jurisdictions must consider if the full public benefits of the NEM are to be realised.

The Commission sees entry conditions imposed by the participating jurisdictions as potentially a major determining factor in the level of contestability in the NEM and, as a consequence, of the magnitude of price benefits which may be passed on to consumers. Adoption of different entry conditions in each jurisdiction may create differences in barriers to entry and competition in the NEM. It is also possible that regulation of entry to the ESI could be used as a form of industry policy, which may have adverse effects on competition in the NEM as a whole.

The Commission therefore supports the provision of uniform and transparent entry conditions. The Commission feels strongly that the public benefits of the proposed arrangements may be lost if the discretionary elements of existing State licensing legislation are not removed, so that entry requirements in all jurisdictions are transparent and consistent. The Commission would like to see the participating jurisdictions commit to a timetable for the development of mutually recognised entry conditions. Failure to commit to such an outcome could leave open the potential for competitive gains to be reduced.

In addition, a lack of structural separation of vertically integrated distribution businesses (DBs) will affect the level of overall competition in the ESI and the extent of any flow-through of benefits to end consumers. Retail entry will be impaired if inadequate ring fencing allows vertically integrated DBs to engage in discriminatory behaviour, in particular discriminatory access pricing.

Each jurisdiction has agreed to provide for ring fencing between distribution and retail arms of integrated businesses. To this end, ring fencing requirements are part of the licensing conditions in Victoria and New South Wales. Both jurisdictions provide for accounting separation but have broad statements only in relation to information disclosure.

The Commission urges that consideration be given to codifying provisions for ring fencing of vertically integrated DBs or, at least, for there to be consistency between jurisdictions on ring fencing requirements. These requirements should also contain strong provisions with respect to information disclosure.

6. Overall assessment of the public benefits and anti-competitive detriment associated with the implementation of the Code

The TPA enables the Commission to grant authorisation for agreements which contravene Part IV. In reaching its decision on whether or not to grant authorisation the Commission has examined the Code carefully in order to assess the potential public benefits arising from the Code's implementation against the possible anti-competitive detriments. The Commission has taken account of submissions it has received from the applicants and from other interested parties, discussions with interested parties and advice from its consultants (a consultancy examining the technical aspects of Chapters 4, 5, 6, 7, 8 and 9 of the Code[7] and a consultancy on the potential for strategic behaviour under the proposed market arrangements given the current market structure).[8]

In assessing the Code, according to its statutory criteria, the Commission believes that although there has been structural and administrative reform at the jurisdictional level, the full realisation of benefits depends upon the implementation of effective national market arrangements. This is because the national arrangements have efficiency benefits in terms of better utilisation of infrastructure and capital than allowed for in the current State based regimes, as well as giving rise to efficiency benefits from transparent and uniform treatment of wholesale participants across the interconnected grid. Benefits will primarily arise from the development of a wholesale electricity market which will facilitate national competitive trading in electricity, including the dispatch of generation on a least cost merit order basis. Benefits will also arise from access to transmission and distribution wires on a non-discriminatory basis, thus facilitating upstream and downstream competition. The benefits of reform arising from efficiencies will be passed on to end users through vigorous retail competition which will also drive efficiency in the upstream wholesale market.

The caveat to realising these benefits is that implementation of the Code as currently drafted may result in the potential for public benefit being partially or fully offset by anti-competitive detriment. That the Code is regarded as imperfect is not entirely unexpected as it is the first attempt to create wholesale trading arrangements and a uniform and transparent access regime in southern and eastern Australia. It also is a first attempt at uniformly codifying a range of engineering standards and practices. Moreover, the interests of industry participants are often competing and it is unlikely there could ever be consensus on all of the Code's detail.

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7 Western Power — *http://www.accc.gov.au/contact/electric.htm*.
8 Melanie, J., and Brennan, D., *National Electricity Market: Strategic Behaviour*, Australian Commodities, Volume 4, Number 1, March Quarter 1997.

However, a number of problems, identified by interested parties and the Commission, detract from the Code and reduce the likelihood that the full benefits of electricity reform will be realised, because:

- market distortions, due to perceived market immaturity, are not removed in a timely manner;
- the market is not allowed to operate due to excessive intervention;
- certain derogations from the NEM arrangements are allowed to continue indefinitely; and
- trading in the NEM is not done in accordance with the Code and within the bounds of the TPA.

Apart from the above concerns the Commission has also identified a range of other shortcomings which impact on the public benefit and which must be addressed prior to market commencement. These are listed in section 7 of this overview and a fuller discussion is contained in the Commission's *Determination.*

Moreover, it can be expected that further problems will emerge once the Code arrangements have been implemented. The Commission believes that these shortcomings can be handled through the Code change process. Hence it is vital that the Code remain a flexible document which can be amended quickly to rectify deficiencies and developments in the market. It is for this reason that the Commission has determined that no further provisions be classified as protected provisions, and the ones that are be re-examined as they have the potential to reduce the Code's flexibility.

Finally, the realisation of public benefits does not solely depend upon the implementation of effective Code arrangements. There are factors external to the Code that are essential to creating the environment in which competitive outcomes will be realised. While market structure and entry conditions set by State and Territory governments are outside the scope of the Code they are important determinants of the market and competitive environment within which the Code will operate.

7. Determination

Although the Commission considers that some of the proposed arrangements and conduct set out in the National Electricity Code would be likely to lessen competition, it also considers that there is likely to be a significant public benefit resulting from the proposed arrangements and conduct. For the reasons outlined in sections 4-14 the Commission concludes that, subject to the conditions set out below, in all the circumstances the proposed arrangements and conduct set out in 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 engaged 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.

The Commission therefore grants conditional authorisation to applications A40074; A40075 and A40076 until 31 December 2010.

The authorisation that the Commission grants is subject to the following conditions:

Conditions of authorisation

C6.1 No further provisions of the Code as currently drafted, or as amended from time to time, may be made protected provisions.

C6.2 Clause 8.3.1(a)(2) must be amended to provide that the only protected provisions of Chapter 8 are clauses 8.3.2 to 8.3.12, clause 8.4 and clause 8.5.

C6.3 Clause 3.9.4(e)(2) must be deleted.

C6.4 Clauses 3.18.1 and 2.12 must be amended to provide that:

(a) only scheduled generators can be required to pay the fees that NEMMCO allocates to the Participant Compensation Fund; and

(b) only scheduled generators who are centrally dispatched are entitled to receive compensation from the Participant Compensation Fund.

C7.1 Clause 2.2.5 must be amended to provide clearly and specifically, with regard to where, how and to whom output must be sold, the circumstances in which a generator may be classified as a non-market generator.

C7.2 Clause 2.12.3(b)(8) must be deleted.

C7.3 Clause 2.12 must be amended to provide that NEMMCO must use the Code consultation procedures in the introduction and determination of participant fees.

C7.4 Clause 2.12 must be amended to provide that:

(a) NECA's budgeted revenue requirement for each financial year, including any shortfall or excess in NECA's requirements from the previous year, is prepared and published separately from NEMMCO's budgeted revenue requirement; and

(b) a separate charge is made to Code participants to meet NECA's requirements as published.

C8.1 (a) Clause 3.3.3(a)(2) must be deleted;

(b) Clause 3.3.4(c) must be amended to provide that the date of effect of a variation in NEMMCO's determination of an acceptable credit rating is not earlier than 30 business days after the date of notification; and

(c) Clause 3.3.10 must be deleted.

C8.2 The Code must be amended to provide that NECA must, within two years of NEM commencement, conduct and complete a review of the principles for

determination of regions as set out in clause 3.5.1(b).

The review must consider the adequacy and appropriateness of these principles, and of any alternative principles that might be added or substituted therefore, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C8.3 The Code must be amended to provide that NECA must, prior to 1 January 2000, conduct and complete a review of the financial impact of distribution losses. The review must consider whether marginal loss factors could be used to calculate distribution losses.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C8.4 The Code must be amended to provide that:

(a) NECA must monitor any significant price variation between the spot prices in any given trading period and the prices forecast and published by NEMMCO for that trading period;

(b) NECA must, in consultation with the Commission, determine guidelines as to what constitutes a significant price variation referred to in (a) above;

(c) NECA must prepare and issue a report every three months, or more frequently if required by the Commission. The report must:

(i) be issued no later than four weeks after the end of each three month period;

(ii) identify and review each significant price variation that has occurred since the previous report;

(iii) provide an opinion as to the reasons and/or causes of each significant price variation;

(iv) be available to members of the public on request; and

(v) be provided to the Commission.

(d) if the Commission requests NECA to provide a report to the Commission on specific market outcomes identified by the Commission, NECA must provide the report to the Commission as soon as possible but no later than four weeks from the date of the request, and must include in the report an opinion on the reasons and/or causes for the market outcomes.

C8.5 (a) Clause 3.9.4(c) must be amended to provide for the Reliability Panel to conduct yearly reviews of the value of VoLL; and

(b) Clause 3.9.4(d) must be amended to provide that changes to the value of VoLL must take effect six months after notification.

C8.6 Clause 3.9.6 must be amended to provide that the zero dispatch price during an excess generation period will apply for only one year from the commencement of the NEM.

C8.7 The Code must be amended to provide that:

(a) any money received by NEMMCO during an excess generation period must be paid to market customers;

(b) NEMMCO must develop a methodology for the calculation and prompt distribution by it of money it receives during an excess generation period, to market customers entitled to that money;

(c) NEMMCO must pay the market customers entitled to that money as soon as possible, and in accordance with that methodology; and

(d) the methodology must be incorporated into the Code.

C8.8 Clause 3.10 must be deleted.

C8.9 Clause 3.11 must be deleted.

C8.10 Clause 3.13.1(c) of the Code must be amended by substituting 'one year' for 'two years' in that clause.

C8.11 Clause 3.15.2(a) must be amended to provide for a back-up system to be used in the event that the electronic communications system fails or is unable to be accessed by some Code participants.

C8.12 Clause 3.15.9(b) must be amended to provide that:

(a) any person can access the information available to market participants, other than confidential information, provided by NEMMCO via its electronic communications system; and

(b) any charge by NEMMCO to persons for provision of access to this information must be on a cost reflective basis.

C8.13 The Code must be amended to provide that NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of clause 3.15 of the Code. The review must consider the adequacy and appropriateness of these provisions, and any alternative provisions which might be added or substituted therefore, in meeting and facilitating the Code objectives. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C8.14 Clause 3.15.10 of the Code must be amended to provide that:

(a) the market audit must be conducted by an entity that is independent of NEMMCO and the market participants;

(b) NEMMCO must either approve and endorse the market audit report and any recommendations therein by noting such approval and endorsement on the report or prepare a separate report dealing with each of the matters within the market audit report that NEMMCO does not approve or endorse; and

(c) the market audit report and any separate report by NEMMCO are to be provided to market participants and are to be made available to the public.

C9.1 The Code must be amended to provide that the reserve trader provisions, contained in clauses 3.14 and 4.8.6 of the Code, end on 30 June 2000.

C9.2 The Code must be amended to provide that NECA must conduct and complete a review of the reserve trader provisions by 30 March 2000. The review must consider the adequacy and the appropriateness of the reserve trader provisions, whether there is a need for a reserve trader in the market, whether there are any alternatives to the reserve trader provisions, whether there are any distortions to market outcomes caused by the reserve trader provisions, and whether there are any alternative provisions which might be added or substituted therefore, in meeting and facilitating the Code objectives. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C9.3 Clause 8.8.1(d) must be amended to provide that the guidelines and policies to be determined by the Reliability Panel to govern the exercise of the reserve trader function are publicly available by 30 June 1998.

C9.4 The Code must be amended to provide that NECA must conduct an annual review of NEMMCO's use of its powers of direction under clause 4.8.10. The review must be conducted on each anniversary of NEM commencement in respect of the preceding year. The annual review must consider for each occasion on which the power was used in the preceding year, whether the exercise and manner of exercise of the power was appropriate in all the circumstances and in accordance with the Code objectives and make any recommendations considered appropriate for future exercise of the power. The report of the review is to be completed within 30 days of the end of each relevant year and is to be made available to all market participants.

C9.5 Clause 3.16.2(a) must be amended to provide that a schedule detailing the matters in clause 3.16.2(a)(1) and (2) is included in the Code.

C9.6 Clause 3.16.2(b) and 3.16.4(a) must be amended to provide that NEMMCO:

(a) must publish on the market information bulletin board, or

(b) otherwise notify without delay,

a material force majeure event or declaration of market suspension.

C9.7 Clause 3.16.4 must be amended to provide that:

(a) within 10 workings days of the suspension being resolved, NEMMCO must undertake an investigation of all aspects of that market suspension; and

(b) NEMMCO must as soon as possible provide a report on the results of the investigation, and must distribute this report to all Code participants as soon as possible and to all interested persons upon request.

C9.8 The Code must be amended to provide that NECA must, within 80 days of the third occurrence in any two year period of a force majeure event (as defined from time to time pursuant to clause 3.16.2(a)) or in any event within five years of the NEM commencement, conduct and complete a review of the provisions of clause 3.16. The review must consider the adequacy and appropriateness of the provisions, and of any alternative provisions that might be added or substituted thereof, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C9.9 Clause 5.5(f)(4) must be amended to provide that:

"compensation to be provided by the *Network Service Provider* to the *Generator* in the event that the *generating units* or group of *generating units* of the *Generator* are *constrained-off* or *constrained-on* during a *trading interval*".

C9.10 Clause 4.8.16 must be amended to provide that the results of any investigation or report in relation to operating incidents, or market suspension, must be distributed to all Code participants, and provided to interested persons on request.

C10.1 The Code must be amended to explicitly recognise the right of third parties to bypass the network.

C10.2 Clause 5.6.3(b) must be amended to provide that the representative from the nominated jurisdictional entity must not be involved with any decision of the IRPC where a conflict of interest between the commercial operation of the entity they represent and the decision of the IRPC may arise.

C10.3 Clause 5.6.5 must be amended to require the Inter-regional Planning Committee to include in its report to NEMMCO consideration of alternative strategies to network augmentation for removing or reducing network constraints.

C10.4 Clause 5.6.5 must be amended to provide that the Inter-regional Planning Committee conduct its public review processes in accordance with the Code consultation procedures.

C10.5 Clause 5.6.5(k) must be amended to provide that, in arriving at its determination under clause 5.6.5(j), NEMMCO must also consider alternatives

to network augmentation including, but not limited to, alternative generation and demand side options.

C10.6 Clauses 5.7.1 and 5.7.2 must be amended to provide that reports of tests and inspections are to be made available to the Code participant whose facilities are being inspected or tested, the Code participant requiring the test or inspection, NEMMCO and any other person who may be affected by the results of the test or inspection.

C10.7 Clauses 5.7.1 and 5.7.2 must be amended to provide that NECA must annually prepare a report detailing the use of inspection and testing rights by all Code participants. The report must be completed within 30 days of each anniversary of the NEM commencement in respect of the preceding year and must be made available to all Code participants and interested persons.

C12.1 Chapter 7 must be amended before 1 July 1998, to include new metering requirements for smaller contestable customers, less than 750MWh per annum.

C12.2 Clause 7.2 must be amended to explicitly permit market participants to change Metering Providers after the meter has been installed.

C12.3 Clause 7.6.1(d) must be amended to allow NEMMCO unrestrained access to a metering installation for the purpose of testing the metering installation.

C12.4 Clause 7.6.3(d) must be amended to allow NEMMCO unrestrained access to conduct periodic random audits of metering installations.

C12.5 Clause 7.6.1(e) must be amended so that the person who tests a metering installation must make the test results available to all interested parties.

C12.6 The Code must be amended to provide that NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of the Code regarding the role of responsible persons. The review must consider possible conflicts of interest of persons performing that role, particularly where the responsible person is a market participant which takes energy from a NSP. The review must also consider any steps which might be taken to remove or ameliorate the effects of any possible conflict of interest it identifies.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C12.7 Chapter 7 must be amended to include guidelines relating to substitution and validation of data.

C12.8 Clause 7.13(a) must be amended to provide that agreements between NEMMCO, a market participant and the local NSP should not be permitted if they materially affect the interests of persons other than the market participant and the local NSP.

C13.1 Chapter 8 must be amended to provide that all intending participants are covered by the dispute resolution provisions.

C13.2 Clause 8.2 must be amended to provide that NECA must, within two years of NEM commencement, conduct and complete a review of clause 8.2. The review must consider the efficacy of the dispute resolution process generally and in particular what, if any, time limitation should be placed upon parties rights to issue dispute notices or invoke the dispute resolution process. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C13.3 Clause 8.3.5(d)(1) must be amended to provide that both Code participants and interested parties are given an opportunity to put submissions to the Code Change Panel in respect of Code changes.

C13.4 Clause 8.5.5 must be amended to provide that operation of the Code shall not commence until the Regulations relating to sanctions referred to in clause 8.5.5(a) have been made.

C13.5 Clause 8.5.1 must be amended to provide that NECA must, using the Code consultation procedures, develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5.1. The guidelines and conditions must also set out those circumstances in which a Code participant is to bear the cost of providing the information sought by NECA, irrespective of whether a breach of the Code has occurred.

C13.6 Clause 8.6.6 must be amended to provide that NEMMCO must also develop and implement policies concerning the protection, dissemination and use of information by each of the bodies and panels established under the Code.

C13.7 The Code must be amended to provide that NECA must, using Code consultation procedures, develop and implement guidelines and conditions with respect to the exercise of its powers pursuant to clause 8.7.2(g). The guidelines and conditions must set out the matters which NECA must have regard to prior to deciding the allocation of costs of any additional compliance monitoring.

C13.8 Clause 8.7.3(b) must be amended to provide that NECA must, as soon as practicable, notify a Code participant of any decision to publish that Code participant's confidential information. Any such decision must be reviewable prior to publication in an urgent application to the National Electricity Tribunal by the Code participant who owns the confidential information.

C13.9 Clause 8.8.3 must be amended to provide that intending participants, as well as Code participants, are entitled to make submissions and attend any of the Reliability Panel's hearings.

C13.10 Clause 8.8.3 must be amended to provide that NECA, within 10 days of receiving the written report of the Reliability Panel must, subject to the applicable confidentiality provisions, make the report publicly available.

C13.11 Clause 8.8.1 must be amended to provide that, the Reliability Panel, in undertaking its review pursuant to clause 8.8.3(b) and in preparing its report, considering reliability of the power system, must limit its considerations to the transmission networks, considering other factors such as generation, demand

side response and distribution networks only insofar as they affect the overall system security.

C13.12 Clause 8.9(a)(1) must be amended to provide that intending participants in the class of participants nominated by the relevant Code provisions are consulted.

C13.13 Clause 8.9(b) must be amended by adding at the end thereof:
'Any decision or determination purportedly made where the consulting party has failed to comply with clause 8.9 when required to do so, is, if made by NECA or NEMMCO, a reviewable decision and is in any case of no force or effect until the requirements of clause 8.9 have been substantially complied with.'

C14.1 Clause 9.8 must be amended to provide that the transmission pricing regulation derogations must end on or before 31 December 2002.

C14.2 Clauses 9.27.1 and 9.27.2 must be amended to specify that the derogation ends on or before 31 December 2002.

C14.3 Clause 9.29.2(j) must be amended to specify that the derogation ends on or before 31 December 2002.

C14.4 The Code must be amended to provide that the derogations in Chapter 9 of the Code, relating to technical requirements of generators and NSPs in Victoria must end on or before 31 December 2002.

C14.5 The Code must be amended to provide that the derogations in Schedule 9D1 of Chapter 9 of the Code, relating to generators in South Australia must end on or before 31 December 2002.

C14.6 Clause 9.22 must be amended to specify which dispute resolution arrangements will apply in the ACT.

C14.7 Clause 9.15 must be amended so that where any conflicts arise out of having IPART act as the Adviser and DRP which might prejudice IPART's ability to implement a fair and efficient dispute resolution process, an alternative Adviser or DRP is selected.

C14.8 Clauses 9.17.1(b) and 9.17.3(d) must be amended to provide that any exemptions to the metering provisions issued by TransGrid must end on or before 31 December 2002.

This determination is made on 10 December 1997**.** 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 C6.2 to C14.8, listed above, have been complied with.

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

- where the application is not withdrawn — on the day on which the Tribunal makes a determination on the review; or

- where 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 C6.2 to C14.8 have been complied with.

This determination applies to the National Electricity Code dated 24 September 1996 and subsequently amended on 21 April 1997 and 23 July 1997.

1. Introduction

On 15 November 1996, the Australian Competition and Consumer Commission (the Commission) received applications for authorisation of the National Electricity Code (the Code). The applications (numbers: A40074, A40075 and A40076) were submitted under Part VII of the *Trade Practices Act 1974* (the TPA), and these, together with the supporting submission, were lodged by the National Electricity Market Management Company (NEMMCO) and the National Electricity Code Administrator (NECA). The Code provides the institutional arrangements, market rules, power system security, network connection, network pricing, metering and infrastructure access principles for a competitive wholesale national electricity market (NEM).

This *Determination* outlines the Commission's analysis and views on the application for authorisation of the Code. This introduction provides some background information by documenting the importance attached to the successful implementation of electricity reforms (section 1.1), recent competition policy reforms (section 1.2) and reform in the electricity industry (section 1.3). The details of the proposed NEM arrangements are summarised in section 1.4. Section 1.5 outlines the transitional arrangements. The Commission's statutory assessment criteria and approach are documented in section 2, while section 3 outlines the public consultation process carried out by the Commission in the lead up to and following submission of the application. The remaining sections detail the Commission's assessment of the application for authorisation.

On 28 April 1997 the Commission received an application from NECA to accept the Code as an industry access Code under Part IIIA of the TPA for electricity transmission and distribution facilities in the Australian Capital Territory, New South Wales, South Australia, Queensland and Victoria. The Commission's assessment of the access Code is the subject of a separate determination, which is being finalised by the Commission. A draft of the determination the *NEM Access Code Draft Determination,* was published on 29 August 1997.

1.1 The importance of electricity reform

The importance of reform to the electricity supply industry (ESI) is underscored by the significant role the industry plays in the Australian economy, as well as by the size of the potential benefits that are likely to accrue from the successful implementation of the reforms.[9]

The ESI is one of Australia's largest economic activities. As an infrastructure industry the ESI ranks third in terms of its contribution to GDP (2.2 per cent in 1994–95) behind communications and road transport. In 1994–95 the industry raised $12.3 billion from electricity sales, employed approximately 42 000 persons and controlled capital assets worth $43 billion.[10]

Electricity provides an important input into all Australian industry influencing the ability of firms to compete both domestically and internationally. On average electricity comprises 0.3

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[9] The electricity supply industry is a generic term which encompasses the production, distribution and sale of electricity to the final consumer.

[10] BIE (Bureau of Industry Economics), *Electricity 1996, International Benchmarking*, Australian Government Publishing Service, Canberra, 1996.

to 6 per cent of industry costs (considerably more for energy intensive industries like smelting and non-ferrous metals),[11] and in total it represents 18 per cent of Australia's energy needs.[12]

Thus the successful introduction of competitive reforms to the ESI is a key to providing strong competitive incentives to participants to improve the efficiency of their production, resource allocation and investment decisions, and to minimise costs. These benefits are not limited to the ESI as electricity provides an important input into all Australian industry, influencing the ability of firms to compete both domestically and internationally. Benefits are likely to be distributed broadly throughout the economy through lower input prices to Australian industry, lower prices to end use consumers, and more efficient use of society's resources. Quantitative estimates of the benefits of Hilmer reforms to the ESI indicate that substantial increases in economic growth, in the order of $5.8 billion (in 1993–94 dollars) or 1.4 per cent of gross national income are achievable.[13]

In addition the Productivity Commission's international benchmarking report argues that an interconnected electricity grid, which provides opportunities for power exchanges between the States, would allow electricity generators to make better use of capital assets and thereby reduce excess capacity and improve productivity.[14]

The need to continually improve the performance of the ESI is recognised not only in Australia but in a number of other countries as well. For instance, the United States of America, England and Wales, New Zealand, Spain, Norway and Sweden have all introduced, or are implementing, significant reform in their electricity industries. These overseas developments place pressure on the Australian ESI to raise its performance standards, as well as providing valuable lessons for Australia. Nevertheless, it must also be recognised that in many respects the Australian reform process is at the forefront of international developments.

1.2 Recent competition policy reforms

Electricity industry reforms gained national prominence at the July 1991 Special Premiers Conference, when the Council of Australian Governments (COAG) agreed to the introduction of a NEM as part of micro-economic reform of government enterprises. At this meeting COAG agreed to the establishment of the National Grid Management Council (NGMC) to advise it in relation to the development of a NEM, and develop the NEM's market and trading arrangements.

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11 BIE, *Electricity 1996, International Benchmarking*, Australian Government Publishing Service, Canberra, 1996. Table A1.6.

12 ABARE (Australian Bureau of Agriculture and Resource Economics), *Energy, Australian Energy Consumption and Production, Historical Trends and Projections to 2009–10,* Canberra, 1997.

13 This benefit was the largest single benefit in the overall Hilmer and related reforms estimated by the Industry Commission (Industry Commission, *The Growth and Revenue Implications of Hilmer and Related Reforms: A report by the Industry Commission to the Council of Australian Governments (Final Report)* Australian Government Publishing Service, Canberra, March 1995). Although the share of the $5.8 billion benefit associated with electricity reform was not explicitly specified by the Industry Commission, an earlier Industry Commission report (Industry Commission, *Energy Generation and Distribution*, Vol 2: Report, No. 11, 17 May 1991) suggested that over 90 per cent of combined electricity and gas reform benefits could be attributed to electricity reform.

14 Productivity Commission, *Electricity 1996 International Benchmarking*, Report 96/16, Canberra, September 1996.

A major step in extending the reach of competition policy to previously sheltered sectors of the economy, such as the ESI, was the commissioning in late 1992 of the report of the Independent Committee of Inquiry into National Competition Policy (August 1993). At the COAG meeting of April 1995, Heads of Government signed agreements to implement the national competition policy reform package. The package included extending the competitive disciplines of the TPA to State government business enterprises and reaffirmed COAG's July 1991 commitment to establish a NEM.

The agreed package of reform measures has provided guidance in relation to the restructuring of the ESI. They have also linked competition payments to the implementation of micro-economic reforms thereby providing an incentive, in addition to identified efficiency benefits, for State governments to pursue reform.

1.3 Recent reforms in the ESI

Since the mid–1980s, the ESI has undergone significant changes to improve performance. Early reforms focused on efficiency improvements, such as increasing labour productivity, while more recently the emphasis has been on administrative and structural reforms.

Administrative reform of the ESI covers a range of policy changes such as the corporatisation of electricity utilities, the creation of a competitively neutral operating environment (that is, separation of commercial and regulatory functions and imposition of tax equivalence and dividend payments) and the establishment of independent pricing authorities. Administrative arrangements have also dealt with transitional issues including the franchising of some customers to specific retailers and vesting contracts for generators.

The extent of structural reform of the ESI has differed between jurisdictions but has generally involved the identification and separation of the more contestable segments of the industry (i.e. generation) from the natural monopoly elements of the industry (i.e. transmission and distribution). In some jurisdictions structural reforms have also increased competition by splitting the various activities of the industry into separate competing companies (e.g. generation). In addition, a number of the generation and distribution companies have been privatised. These structural changes have often been accompanied by changes in the regulatory arrangements.

Details of the process of electricity reforms, and the present structure of the ESI in each participating jurisdiction are set out in Chapter 3 of the applicants' submission.

1.4 The National Electricity Code

The final version of the Code submitted to the Commission has been endorsed by the participating jurisdictions, New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory. These jurisdictions have agreed to enact co-operative legislation, the National Electricity Law (NEL), 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. Tasmania is expected to join the NEM some time in the future. There is some question as to whether or not Western Australia and the Northern Territory will join the NEM given their distance from other population centres in Australia, and the limitations of current transmission technology.

The Code is designed to set out the rules governing the operation of the NEM, market trading rules, network pricing principles, systems control and access to the network, as well as the rights and obligations of Code participants.

One of the Code’s stated objectives, as agreed by all participating jurisdictions, is to provide a regime of light-handed regulation to achieve the market objectives, which are:

- the market should be competitive;
- customers should be able to choose which supplier (including generators, retailers and traders) they will trade with;
- any person wishing to do so should be able to gain access to the interconnected transmission and distribution network;
- a person wishing to enter the market should not be treated more favourably or less favourably than if that person were already participating in the market;
- a particular energy source or technology should not be treated more favourably or less favourably than another energy source or technology; and
- the provisions regulating trading of electricity in the market should not treat intrastate trading more favourably or less favourably than interstate trading of electricity.

NECA, a company incorporated under the Corporations Law and limited by guarantee, is to administer and enforce the Code. NECA is owned by the participating jurisdictions as members. Matters concerning the operations and powers of the company, such as initial capital injections, special requirements for the exercise of the company’s powers and the criteria for selection of directors, are set out in the NECA Members Agreement.

NECA’s regulatory powers do not extend to safety, the environment and customer franchise pricing. These three areas will continue to be regulated by the individual jurisdictions.

NEMMCO is to manage the operation of the market and power system security. NEMMCO’s objectives, powers and responsibilities are defined in the Code and the NEMMCO Members Agreement. NEMMCO has a similar corporate structure to NECA and is likewise owned by the participating jurisdictions as members.

The Code covers the operation of the wholesale spot market. Trading in the wholesale spot electricity market will include bilateral contracts, spot trading, and may include the facilitation by NEMMCO of trading in the short term forward market (STFM) and IRH market. Although the Code does not cover arrangements for bilateral contracts, it does not prohibit them, nor does it extend to the arrangements for retail trading.

The output of all generating units capable of producing energy at greater than 30MW will be required to be traded through the wholesale market and be subject to the spot price — unless the generating unit has received an exemption from NEMMCO. Trades through the spot market will be conducted so that all demand is satisfied at each instant. Trade is conducted by way of bids by generators setting out the price and quantity of electricity they are prepared to sell in each trading interval.

NEMMCO will be responsible for co-ordinating the dispatch of loads and scheduled generating units in least cost merit order, and determining the spot market clearing price. NEMMCO will settle spot market transactions, and may optionally reallocate spot market credits and debits from bilateral trades as notified by market participants. NEMMCO may also assist in the billing and settlement of transactions in the STFM and IRH market if it facilitates the development of such markets.

Responsibility for power system operation is vested in NEMMCO, through its control of the central dispatch process, and the collection and dissemination of information. Where there is a clear risk of involuntary load shedding NEMMCO has the power to contract for reserves, and as a last resort may intervene in the market.

While the generation and retail sectors are to be opened up to competition, the electricity network required to transport electricity from generators to end users (whether transmission or distribution systems) are recognised as natural monopolies, and will be subject to an access undertaking and regulation as set out in the Code.

1.5 Transitional arrangements

The jurisdictions participating in the NEM are at different stages of the reform process. In order to account for this the NEM is to evolve through a managed transition.

Preceding significant structural reform in New South Wales and Victoria the two States began operating separate wholesale competitive electricity pools in May 1996 and October 1994 respectively. The State based arrangements did not allow for any commercial trading of electricity between the two pools.

In order to facilitate the transition to the NEM, on 23 December 1996 the Commission received an application from New South Wales, Victoria and the Australian Capital Territory to initiate the harmonisation of the New South Wales and Victorian wholesale electricity markets. These arrangements are known as NEM1, and there are two stages to the NEM1. The Commission granted interim authorisation to the NEM1 Stage 1 arrangements on 5 March 1997, and the harmonised New South Wales and Victorian wholesale market began operating on 4 May 1997.

The Commission is awaiting an application for authorisation of Stage 2 of the NEM1 arrangements which will involve the introduction of a market for ancillary services.

The South Australian and Queensland ESIs are currently undergoing structural reforms. Interim market arrangements have commenced in Queensland (as of October 1997) with the intention of these arrangements converging with the National Code when the NEM commences in 1998. Physical interconnection is planned for 2000–2001. South Australia will join the NEM when it starts in March 1998.

In addition, as part of the transition process, each of the participating jurisdictions has submitted for authorisation departures or ‘derogations’ which are contained in Chapter 9 of the Code. The derogations are designed to give those jurisdictions who have chosen to do so exemptions from particular portions of the Code.

2. Statutory test

Authorisation provides protection from action by the Commission or any other party for potential breaches of certain restrictive trade practices provisions of the TPA.

The applications for authorisation were made under Division 1 of Part VII of the TPA, specifically:

- s. 88(1) of the TPA, insofar as the applications sought authorisation:
  - to make and give effect to a provision of a contract, arrangement or understanding where the provision is, or may be, an exclusionary provision; or
  - to make and give effect to a provision of a contract, arrangement or understanding where the provision is, or may be, an exclusionary provision or has the purpose, or has or may have the effect, of substantially lessening competition, (including any deemed lessening of competition through price fixing arrangements within the meaning of s. 45 of the TPA);
- s. 88(8) of the TPA, insofar as the applications sought authorisation:
  - to engage in conduct that constitutes or may constitute the practice of exclusive dealing, as defined in s. 47 of the TPA.

The TPA provides that the Commission shall only grant authorisation if the applicants satisfy the relevant test in s. 90(6) of the TPA. This section provides that the Commission shall not grant authorisation unless it is satisfied in all the circumstances that:

- the provisions of the subject arrangements 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 arrangements or conduct.

Sub-section 90(8) provides that the Commission shall only grant authorisation in relation to the application under sub-s. 88(1) (the exclusionary provisions) if it is satisfied in all circumstances that the conduct would result, or would be likely to result, i such a benefit to the public that the arrangement should be allowed to take place.

Authorisation is granted in order to provide immunity for possible breaches of s. 45 and/or s. 47 of the TPA. In regard to breaches of s. 47 only the applicants are provided such immunity.

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

- have the purpose or 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 which are restrictive and/or anti-competitive. One form of exclusive dealing prohibited outright by the TPA is third line forcing, which involves the supply of goods or services on condition that the purchaser acquire goods or services from a particular third party.

In deciding whether it should grant authorisation the Commission must examine the anti-competitive aspects of the scheme, the public benefits arising from the scheme and weigh these two to determine which is the greater. Should the public benefits or expected public benefits outweigh the anti-competitive aspects the Commission may grant authorisation which may in turn be subject to conditions.

If that is not the case the Commission may refuse authorisation or alternatively, in refusing authorisation, indicate to the applicant how the applications could be restructured to change the balance of detriment and public benefit so that the authorisation may be granted.

3. Public consultation process

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

In response to version 1.0 of the Code the Commission released an issues paper entitled the *National Electricity Market — Issues Paper* (March 1996). The purpose of the issues paper was to facilitate public discussion on the competition, access and public benefit implications of version 1.0 of the Code. Thirty-two written submissions were received in response to the issues paper, and the key issues arising from submissions and the Commission's preliminary analysis were published in a paper *National Electricity Market Code of Conduct — Comments and Issues Arising* (June 1996).

The Commission received the formal applications for authorisation of the Code on 15 November 1996. It informed the public of receipt of the applications by way of advertisements in newspapers and by contacting interested parties. 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 Code. The Commission also undertook discussions with a cross section of interested parties on the competition issues arising from the Code. A list of these parties is set out in Appendix A.

To assist the Commission's assessment of the Code, four consultants were engaged by the Commission. Western Power Corporation assessed the technical provisions in the Code and Colin Taylor and Associates reviewed Western Power's findings.[15] ABARE was engaged to examine the potential for strategic behaviour in the NEM[16] and the National Economic Research Associates (NERA) were engaged to review the Victorian derogations regarding the regulation of transmission network pricing.[17]

On 21 April 1997 the applicants amended the Code, and on 28 April 1997 submitted the Code as an access Code under Part IIIA of the TPA. Further amendments to the Code were submitted to the Commission on 23 July 1997. In both instances, in order to fulfil its statutory obligations, the Commission sent out copies of the amendments to the Code to all interested parties and called for submissions on the amendments. Overall 58 submissions were received on the Code, and a list of parties who made submissions is in Appendix B. The Commission has created a separate public register file for each of the Code applications for authorisation. With the exception of one submission which has been excluded on confidentiality grounds, all submissions have been placed on this public register.

The Commission produced a draft determination on 29 August 1997 outlining its analysis and views on the Code authorisation application, according to the statutory assessment criteria outlined in section 2. The Commission invited the applicants or other interested persons to notify it within 14 days, whether the applicants or other interested persons wish the

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15 The Western Power Technical Report can be accessed from the Commission's Web site at *http://www.accc.gov.au/contact/electric.htm*.

16 Melanie, J., and Brennan, D., *National Electricity Market: Strategic Behaviour*, Australian Commodities, Volume 4, Number 1, March Quarter 1997.

17 Draft reports only, *Regulation of PowerNet Victoria: A description of the Victorian proposals*, and *Regulation of PowerNet: An evaluation of the Victorian proposals*, Rachel Goodyer and Greg Houston, August 1997.

Commission to hold a conference in relation to this draft determination.[18] The Australian Cogeneration Association (ACA) so notified the Commission on 29 August 1997.

The pre-decision conference was held in Melbourne (with video links to Sydney, Brisbane, Canberra and Hobart) on 18–19 September 1997. Around 92 interested parties attended the conference.

Interested parties were given an opportunity to submit further submissions to the Commission following the pre-decision conference. The Commission received 52 submissions addressing issues raised at the conference or in the draft determination. This determination takes into account the issues raised at the pre-decision conference and in submissions.

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[18] For the purposes of the pre-decision conference, an interested person is a person who has notified the Commission in writing that the person, or a specified unincorporated association of which the person is a member, claims to have an interest in the application and the Commission is of the opinion that the interest is real and substantial.

4. Definition of the market

The applicants have defined the relevant market as:

> the supply and use of electricity by wholesale market participants in New South Wales, Victoria, South Australia, Queensland and the Australian Capital Territory.

The main issues raised by this market definition are:

- Is the functional market appropriate?
- Is the product market limited to electricity or is there a broader energy market?
- Does the geographic boundary of the market extend to all five jurisdictions, or are the geographic markets local or regional in scope?

Issues concerning the relevant functional, product and geographic markets are discussed below.

The functional market

Although not discussed by the applicants in their market definition there would appear to be a number of distinct functional levels in the electricity market. In order to promote competition in electricity generation and supply, structural reforms have been introduced to separate formerly integrated public utilities along functional lines and establish open access to transmission and distribution networks. The functional levels therefore would appear to consist of the vertical stages of the electricity market (generation, wholesale institutional arrangements, and arrangements for market customers) and the complementary natural monopoly transport services (transmission, distribution). It is noted that there is no accepted definition that enables entirely consistent separation of the functional levels in the electricity market, especially between transmission and distribution. The applicants' definition is accepted for present purposes except that it is considered more accurate to refer to the 'acquisition', rather than the 'use', of electricity by market participants.

The product market

The question of whether the relevant market is an electricity market or a wider energy market largely hinges on the extent of substitution possible between electricity and other energy forms — in particular natural gas.[19]

The Industry Commission (IC) defined electricity usage in terms of meeting the energy requirements of two broad end-use categories: those uses for which no alternative form of energy can be used (the exclusive market) and uses for which gas and/or other energy sources can be substituted for electricity (the shared market).[20] There are many applications for which there currently are no technologically or economically viable substitutes for electricity. There are, however, other applications where gas may be substituted for electricity more readily, most notably in water heating, space heating and cooking applications.

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19 An important factor limiting choice of alternative fuels beyond natural gas is environmental pollution controls. Electricity and gas are 'clean' fuels, and other fuels are generally not possible substitutes, particularly for industrial applications in metropolitan areas.

20 Industry Commission, *Does Pacific Power have Market Power?* August 1995, pp 45–47.

In the shared segment of the market, variation in electricity use reflects the availability of alternative fuels, relative energy prices, mix of industries, climatic conditions and space heating requirements. Although other forms of energy can be switched for electricity in some uses, this substitution usually takes time. This is because substitution often does not just involve a change in energy source — it frequently also requires changes to, or the replacement of, the appliance/equipment using the energy source. This can represent a major sunk cost relative to income, strongly affecting the ability to achieve savings by switching energy source. In the residential sector switching to gas for hot water heating, for example, requires the purchase of a new hot water system. The difficulties in substituting other forms of energy for electricity are even more marked in the industrial sector. These difficulties have been highlighted by the Natural Gas Corporation of New Zealand.

> It must be emphasised ... that very few interfuel energy choices are made outside of decisions about plant expansion or capital replacement and this decision depends not only on the relative fuel costs, but also on the capital cost of equipment, capital costs of associated plant that may be necessary, expected non-fuel operations and maintenance costs, the efficiency of energy conversion and use, and the impact of the use of the alternative fuels on the production itself. Investment of the capital solely to reduce cash operating costs in fuel purchases is seldom economic because of the low opportunity cost of sunk investment in existing energy plant, and therefore energy use decisions are almost invariably associated with a need to add to, or replace, the capacity of existing energy plant.[21]

Many energy users are, therefore, restricted in their ability to switch energy forms because of the fuel specifications of the plant they have chosen to install. For these users it may be practical to switch only towards the end of the economic life of the plant in question. As the economic life of major plant items is accepted as being typically 10–15 years, energy users may largely be locked in to a particular energy form for substantial periods of time.

Industrial energy users may also have little ability to substitute other forms of energy for electricity because of the existence of long term energy supply contracts. The existence of such contracts partly represents the need of market participants to recover the high sunk costs associated with electricity generation and transmission. Accordingly, electricity utilities have traditionally tied in large end use consumers with long term take-or-pay contracts, an example being the long term arrangements the State Electricity Commission of Victoria (SECV) has with Alcoa of Australia for the Portland and Point Henry Smelters.

The above analysis suggests that the ability to substitute alternative energy sources for electricity is quite limited in many applications. A recent study by the Australian Gas Association (AGA) and ABARE which analyses the price elasticities of Australian energy demand from 1973–74 to 1993–94 reaches the same conclusion.[22] The study found that electricity demand is relatively inelastic. In other words, electricity demand is relatively unresponsive to electricity price changes. Of the three sectors, residential, commercial and industrial, the study concludes that electricity demand is least price responsive in the industrial sector. This tends to indicate that industrial electricity users cannot vary their usage following a change in the price of electricity.

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21 Quoted in Commerce Commission, *Defining Energy Markets for Competition Analysis*, New Zealand, August 1993, pp 16–17.

22 The Australian Gas Association and ABARE, *Price Elasticities of Australian Energy Demand*, AGA Research Paper No. 3, Australian Gas Association, September 1996.

The AGA/ABARE study indicates that across all three sectors there is a low responsiveness in electricity demand to changes in the prices of gas and other fuels. In the residential sector, the study notes that there is a low responsiveness of electricity demand to changes in gas prices. This appears to be due to the limited substitution possibilities from electricity to gas.

In the industrial sector the quantity of electricity demanded is even less responsive to changes in the prices of other energy sources. Indeed, the AGA/ABARE study concluded that there is no responsiveness in electricity demand to a change in the price of gas. This tends to confirm the view that industrial users of electricity are locked into electricity as an energy source. The study, however, places a caveat on these results, noting that significant variations across industries could be hidden.

Given these considerations it is unlikely that electricity will receive much competition from gas or other energy sources, at least in the short term. There may well be competition at the margin in new residential developments and factories on the metropolitan fringes, but in many cases it will simply not be feasible to substitute other energy sources for electricity. At the current time, therefore, the Commission accepts that the relevant market is an electricity rather than energy market. In the longer term, however, it is possible that technological developments, as well as reforms in both the gas and electricity industries, may have an impact on the degree of interfuel competition.

Geographic market

The geographic market is the geographic area or areas in which sellers operate and to which purchasers can practicably turn for such goods and services.

The applicants state that the market will initially incorporate the interconnected electricity networks in New South Wales, Victoria, South Australia and the ACT. They argue that the production and sale of electricity and the provision and use of network services in these jurisdictions will adhere to the arrangements set out in the Code. These jurisdictions are participating due to their ability to be interconnected. It is anticipated that Queensland, a signatory to the Code, will be interconnected at the inception of the full NEM, whilst there is a possibility that Tasmania will join if it becomes interconnected. Technical and economic limitations imposed by interconnection across long distances mean that the Western Australian and Northern Territory systems will be self contained markets outside the NEM for the time being.

The applicants argue that with the full implementation of the NEM, participants in any participating jurisdiction will be able to buy and sell electricity in any other participating jurisdiction. Dispatch of electricity will be co-ordinated centrally based upon dispatch bids and offers made in accordance with the Code. Thus each region will be subject to competitive pressures arising from possible sales by participants in other jurisdictions. Accordingly, the applicants state that the relevant geographic market incorporates all participating jurisdictions.

The geographic scope of the market, however, may be affected by constraints on the transmission of electricity between jurisdictions and even within the larger jurisdictions such as Queensland. These limits are imposed by:

- unavoidable losses associated with long distance transmission of electricity. The delivery of electricity over long distances through high voltage transmission lines is subject to significant energy losses. Losses increase according to the distance involved. In the

NEM this can place inter-state generators at a competitive disadvantage relative to local generators.

- the capacity of the high voltage power line network. The capacity of transmission linkages between jurisdictions influences the geographic scope of the market. The IC estimates that the current nominal capacity of the link from Victoria to New South Wales represents around 10 per cent of peak demand in New South Wales.[23] If interconnection constraints inhibit trade in electricity, inter-state generators are once again placed at a competitive disadvantage relative to local generators. In a competitive market encouraging inter-state trade, however, it is possible that the capacity and use of the linkages would increase significantly.

At the present time the Commission is of the view that the relevant geographic market for present purposes, i.e. considering the public benefits and anti-competitive detriments of the Code, is the listed jurisdictions of New South Wales, Victoria, South Australia, Queensland and the ACT.[24] However, if under the NEM inter-state trade in electricity is limited by transmission constraints, it may be that the geographic markets associated with the NEM are State or region based pending such constraints being overcome.

Conclusion

Market definition in the energy sector requires a case by case approach. The factors which impact on competition differ substantially in individual cases. Circumstances vary with geographic regions, the functional level of the market and energy applications. The impact of regulatory changes affecting energy markets will not be uniform. How and where market power may arise will depend on a range of factors, few of which will be consistent throughout the economy. Factors which may be relevant in the consideration of market definition include:

- the availability of energy forms which provide practical substitutes for affected customers;

- historical price, demand, and cross-elasticity information;

- the impact of regulatory reforms and structural changes on past market behaviour;

- the length of time for substitution to occur in response to changing market conditions;

- the evidence of supernormal profits by sole suppliers of particular energy forms; and

- the ability of energy suppliers to price discriminate between different classes of customers.[25]

In consideration of this application for authorisation, the Commission accepts as reasonable the applicants' view that the relevant market is currently an electricity rather than energy market. At the current time the majority of end use consumers (industrial, domestic and residential) are unable to substitute alternative forms of energy for electricity.

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23 Industry Commission, *Does Pacific Power have Market Power?*, August 1995, p. 50.
24 This finding assumes that all these jurisdictions will be interconnected at the inception of the NEM.
25 These factors are considered in Commerce Commission, *Defining Energy Markets for Competition Analysis*, New Zealand, August 1993.

The energy sector and particularly the electricity and gas markets are, however, in a period of transition. The electricity sector is in transition to a full NEM. In time, new generation, augmentation and interconnection capacity may develop. It is also possible that independent wholesale and retail traders may enter the market and new generation technologies may be introduced. These developments may result in changes to the nature of electricity demand.

The Commission also accepts that the appropriate geographic market for considering the authorisation application encompasses the listed jurisdictions of New South Wales, Victoria, South Australia, Queensland and the ACT.[26] The Commission notes, however, that transmission constraints, especially at peak periods, may mean that geographic markets may be State or region based at certain times or until these constraints are overcome. It is only when the NEM is operational, however, that the effects of these constraints will be evident.

The Commission accordingly accepts the relevant market, assuming interconnection of the relevant jurisdictions, as:

> the supply and acquisition of electricity by wholesale market participants in New South Wales, Victoria, South Australia, Queensland and the Australian Capital Territory.

[26] The Commission acknowledges, however, that within these jurisdictions there may be isolated systems, which may not form part of the market.

5. Benefits from non-Code reforms

The recent reforms in the ESI outlined in section 1 are important to achieving the projected benefits of the reform process. However, many of the structural reforms are taking place outside the ambit of the Code and this authorisation.

Structural reforms are designed to separate the competitive elements (generation and retail) while regulating the network monopolies (transmission and distribution). Effective structural reform, which will assist in passing benefits through to consumers, will come from:

- the introduction of competition into the wholesale market;
- effective regulation of network monopolies; and
- facilitation of retail competition.

The Code provides the arrangements to establish a single wholesale market for electricity and an access regime for the transmission and distribution networks in the participating jurisdictions. The Code does not cover retail arrangements as these are left to the individual jurisdictions.

The Commission's analysis of the Code indicates that its operation is premised on a number of design features which are not included or covered in the Code but are necessary to obtain the benefits of reform. The most significant of these considered by the Commission for the commencement of the NEM are:

- potential market power possessed by generators arising from insufficient structural reform;
- vertical integration of distribution businesses (DBs); and
- mutual recognition of eligibility requirements/consistent licensing regulations.

This section examines these obstacles to the development of upstream and downstream competition in the supply of electricity. The Commission's purpose is to emphasise that while having the Code is an essential step, more remains to be done to eliminate other significant barriers to competition at the upstream and downstream level of supply in order to realise the benefits of reform.

5.1 Market power and market structure

The design of the NEM as specified in the Code and the industry structure emerging in participating jurisdictions has important implications for the development of effective competition in the NEM, and consequently for the benefits to consumers arising from the reform process. Market power leading to strategic behaviour in the NEM could arise from either market structure and/or market design. Market power can be used to engage in anti-competitive behaviour, and the use of market power imposes a cost on society that can diminish the public benefit from reform.

If market power is used to raise the spot price above the cost of production, inefficiencies will arise in the market, reducing the level of public benefit. For example, the existence and use of market power can reduce the drive for least cost production because of weaker external pressures to keep prices down. Similarly, investment decisions may be sub-optimal because the price of electricity is higher than otherwise, and because of the reduced incentive on the part of those exercising market power to make appropriate investment decisions. Finally, allocative inefficiencies arise because prices are higher and output lower than if there was effective competition.

Market power in the NEM may stem from a number of factors and their interaction. The most significant of these are:

- the non-disaggregation of generation, or insufficient disaggregation;
- anti-competitive conduct by and between generators;
- demand during certain times of the day, seasons or random fluctuations;
- the capacity of interconnection — the greater this capacity the less likely that an entity will have regional market power;
- the ease with which new entrants may be able to enter and exit the market; and
- the impact of market rules/market design on incentives.

However, of principal concern to the Commission for the commencement of the NEM is the influence of market structure on market power, and the apprehension that insufficient structural disaggregation may allow generators to exercise market power.

Analysis of the structure of the NEM by the Commission's consultants, ABARE, indicates that the NEM is characterised by a significant degree of market concentration, particularly in South Australia and New South Wales.

ABARE finds that the current market structure is such that large generation portfolios in South Australia and New South Wales would be in a position to dominate particular segments of the market. This occurs because in periods where the level of demand is high relative to the capacity of rival generators, an individual generator may face a residual demand and hence be in a position to bid 'strategically' to maximise profits. By contrast, in low demand periods when the combined capacity of rival generators is greater than demand no single supplier faces a residual market, and competitive pricing is likely to result as generators compete for a share of the limited market.

ABARE's modelling results indicate that strategic behaviour during periods of high demand could lead to significant increases in electricity spot prices. All generators in the NEM are estimated to benefit from the higher operating surpluses resulting from strategic behaviour by major players. Therefore, according to ABARE large generation portfolios in New South Wales and South Australia would have strong incentives to bid strategically.

ABARE notes that regulation can provide a check on the exercise of market power. However, it suggests that structural reform such as further disaggregation of generation assets may be necessary, not only to reduce the need for regulatory intervention, but also to ensure that the competitive benefits from the implementation of the NEM are attained. Establishing more generation businesses to compete in the market should make it more difficult to exercise market power as it results in capacity demanded being distributed among a number of competing businesses. This means that it becomes much riskier for any one generator to assume that it will be the marginal producer, forcing it to bid into the pool at marginal cost to ensure dispatch.

International experience, particularly from the England/Wales market, has shown just how significant market structure is to achieving the benefits from reform.[27] Moreover, international experience provides guidance on just how important it is to formulate an appropriate regulatory and industry structure prior to privatisation. Once the industry has been privatised it becomes much more difficult to address anti-competitive problems arising from structural and regulatory issues.

Market structure is not addressed in the Code and is a matter for the individual jurisdictions to consider. However, market structure is fundamental to realising the benefits which may arise from implementation of the Code, and a competitive structure is the foundation of the Code's design. The Commission strongly urges the participating jurisdictions to examine the structure of their generation sectors with a view to restructuring to minimise the potential, now and in the future, for generation businesses to exercise any market power they may possess. This is because, to the extent that generation businesses hold market power, the public benefits of the NEM reforms will be reduced or negated. In particular the South Australian Government is urged to consider effective regulation of generation in that State. Moreover the New South Wales Government is urged to consider the further disaggregation of its portfolio generators.

The Commission notes that the issue of market structure is not only crucial at the commencement of the NEM but will be of on-going interest, particularly in respect of possible re-integration of firms participating in the NEM. The Commission's concerns include possible mergers within each segment of the market and also arrangements whereby NEM participants operate in upstream or downstream markets (such as a generation company also operating a retailing business). In this regard the Commission is responsible for assessing whether each merger or acquisition results, or is likely to result, in a substantial lessening of competition in the relevant market or markets, pursuant to s. 50 of the TPA.

5.2 Effective retail competition

Retail competition is not specifically covered by the Code, but will continue to be the subject of jurisdictional regulation. Effective retail competition is vital to delivering public benefits from the ESI reforms to end use consumers. This issue is raised by the Energy Users' Group who highlight the costs of inconsistencies between jurisdictions with regard to metering arrangements, account numbering, customer aggregation guidelines and mutual recognition of licensing legislation. Inefficiencies or lack of competition at the retail level could result in the benefits from competition in the wholesale market being negated. Therefore the Commission views retail competition as an important market reform issue that jurisdictions must consider if the full public benefits of the NEM are to be realised.

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[27] See for example R. Green and D. Newbery, 'Competition in the Electricity Industry in England and Wales', *Oxford Review of Economic Policy*, Vol. 13, No. 1, Spring 1997.

5.2.1 Vertically integrated Distribution Businesses

Vertical integration of DBs may impact on retail competition and access to distribution networks, thus affecting the public benefit which is achievable from the implementation of the Code.

In most jurisdictions the incumbent DBs incorporate both a regulated 'wires' business and a competitive retail business. Queensland may be the exception as a policy has been announced that there will not be a one to one relationship between the 'wires' business and any retail business. If separation of these businesses is ineffective, cross subsidisation from the monopoly to the competitive part of the business may occur in a non-transparent way and information not available to competitors may be passed on to the retail arm. Thus, the host retailer could have a competitive advantage over independent retailers.

A related issue which has been raised with the Commission is that host retailers may cross-subsidise from franchise to contestable customers within their distribution area. Independent retailers may be competitively disadvantaged by such conduct. However, the Commission notes that this may not be an issue after 2000 when all end use consumers will be contestable.

What is required at a policy level is effective separation of the regulated monopoly activities from the competitive activities in these vertically integrated businesses. The Commission is of the opinion that structural separation of the DBs would be the ideal solution. An alternative is the implementation of effective ring fencing between different business functions. Ring fencing — defined in this instance to cover accounting or legal separation and information disclosure limitations, including if necessary, separate legal entities — would promote competition by notionally separating the natural monopoly activities from the competitive activities.

Each jurisdiction is to provide for ring fencing between the distribution and retailing arms of host retailing businesses.[28] To this end, the requirements for ring fencing of the 'wires' business from the retail business are part of the licensing conditions in Victoria and New South Wales. Both jurisdictions provide for accounting separation but only have broad statements in relation to information disclosure.

The Commission is of the view that it would have been advantageous from an economic efficiency/competition policy point of view for effective ring fencing of vertically integrated DBs to be covered by the Code (noting that access to distribution wires is covered by the Code). In particular, this would have given consistent protection across jurisdictions. As the situation now stands regulatory uniformity in ring fencing could be difficult to achieve. The Commission notes that the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code) includes provisions specifying minimum ring fencing requirements between the functions of transporting gas and selling and producing gas and has provisions limiting information disclosure.

The Commission believes that discriminatory access pricing could impair retail market competition and this could reduce the public benefits (price and efficiency gains) of the competitive electricity reforms. Also, access will be impaired if inadequate ring fencing

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[28] See COAG Communiqué, *Report on Electricity Reform*, 19 August 1994.

allows vertically integrated DBs to discriminate against different classes of end use consumers.

The Commission urges that consideration be given to codifying provisions for ring fencing of vertically integrated DBs or, at least, for there to be consistency between jurisdictions of ring fencing requirements and between gas and electricity, given the convergence between these sectors. These requirements should also contain strong provisions with respect to information disclosure.

5.2.2 Retail licensing requirements

The Commission sees entry conditions imposed by the participating jurisdictions as potentially a major determining factor of the level of contestability in the NEM and, as a consequence, the magnitude of price benefits which may be passed on to end use consumers. Any person wishing to buy or sell electricity through the spot market must not only comply with the requirements of the Code, but also with those of the jurisdiction in which he/she wishes to trade. Adoption of different entry conditions between jurisdictions may create differences in barriers to entry and competition in the NEM.

In New South Wales and Queensland, market entry is determined by the Minister under State legislation. This raises concerns about whether decision making is sufficiently independent from political influence in these jurisdictions. Indeed, States could use the discretion provided by State legislation to implement a form of regional development policy. These arrangements would appear to run counter to the philosophy and objectives of the NEM, which are to provide open access on a non-discriminatory basis. Accordingly, the Commission notes that the public benefits of the NEM may be enhanced if most discretionary elements of State licensing are removed such that entry requirements are transparent and consistent in all jurisdictions.

Different conditions of entry in each jurisdiction may also involve high transaction costs for participants, such as retailers, who wish to participate in more than one jurisdiction. If different entry requirements were put in place in each of the jurisdictions, major barriers to trading nationally could be created thereby limiting the level of competition in the NEM. Accordingly, the public benefits of the NEM could clearly be limited.

As a means of addressing these problems the Commission would strongly encourage the participating jurisdictions to discuss the possibility of mutual recognition in areas such as retail licensing. The Commission would like to see the participating jurisdictions commit to a timetable for the development of harmonised entry conditions. As highlighted by the Office of Regulation Review, the benefits to end use customers of mutual recognition can include greater competition, enhanced product choice and lower prices.[29] Failure to commit to such an outcome could leave open the potential for the gains from competition being diminished.

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[29] See COAG Communiqué, *Report on Electricity Reform,* 19 August 1994.

6. General Code considerations

Several general issues are raised by the Code arrangements which do not fit neatly into other sections in this *Determination*. These include the provision for certain clauses to be protected, the limits placed on the liability of NEMMCO and NECA and related bodies, the complexity of the Code and the market design.

6.1 Protected provisions

Some provisions of the Code are classified as protected provisions. Clause 1.1.3 states that under the provisions of the NEL a provision of the Code which is classified as a protected provision may not be amended except with the unanimous approval of the Ministers of all participating jurisdictions. If a provision of the Code is inconsistent with a protected provision, the incumbent provision has no effect to the extent of the inconsistency.[30]

The provisions of the Code that are protected are:

1.3	Market objectives
1.4	Code objectives
1.5	Code administrator
1.6	Market administrator
1.12	Access undertaking
3.2.9	Liability of NEMMCO
3.9.4	VoLL (Value of Lost Load)
4.3.2(e)–(i)	Power system security — NEMMCO's obligations
6.2.1(a)	National regulatory arrangements
Chapter 8	Administrative Functions

Of these, the Commission is mainly concerned with the protected provision status of VoLL and Administrative Functions.

VoLL is set at $5 000/MWh. It is a price cap which is to be applied to determine regional reference prices when there is sufficient generation available to meet demand. Clause 3.9.4 also sets out that the Reliability Panel is to undertake a review of the value of VoLL within 12 months of the commencement of the NEM. [31] The Code also sets out that any change recommended by the Reliability Panel is to be dealt with under the Code change provisions

[30] See NEL, Schedule, Part 2, s. 7.
[31] The Reliability Panel is discussed in section 13.6.

of Chapter 8, but will not take effect until two years after the date of notice of change being published. [32]

Chapter 8 covers dispute resolution, Code change, derogations, enforcement, confidentiality, monitoring and reporting, the Reliability Panel and Code consultation procedures.[33]

Issues for the Commission

The Commission notes that the existence of protected provisions in the Code may not contravene the TPA, the reduced flexibility of the Code may have a detrimental effect on the level of public benefit due to the reduced ability of administrative bodies to respond to dynamic market needs.

What the interested parties say

EnergyAustralia states that it is very disturbing that all of Chapter 8 has been deemed a protected provision. It says that, due to the relative infancy of the NEM, the initial version of the Code will require alteration and the method to allow for change must be amenable to accommodating such changes. Further, energyAustralia argues the proposal that the unanimous support of all Ministers in participating jurisdictions must be obtained for any change to **any** protected provision raises significant questions of workability and practicality. It suggests that the protected provision status covering **all** of Chapter 8 is unnecessary, since governments have more than adequate recourse through NECA and directly to the Commission should they feel that changes to the Code are or are not warranted.

Issues arising from the draft determination

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

C6.1 No further provisions of the Code may be made protected provisions.

C6.2 Clause 8.3.1(a) must be deleted so that the protected provision status of Chapter 8 is removed.

C6.3 Clause 3.9.4(e) must be deleted so that the protected provision status of the VoLL provisions is removed.

At the pre-decision conference, and in subsequent submissions, there were no objections to condition C6.1. There was general support at the pre-decision conference for condition C6.3, which removes the protected provision status of the VoLL provisions. CitiPower and Eastern Energy have subsequently argued that the VoLL provisions should be protected.

The applicants indicated at the pre-decision conference and in their subsequent submission that they will comply with conditions C6.1 and C6.3.

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32 The price cap and the conditions of authorisation imposed by the Commission are set out in section 8.6.
33 Discussed in section 13.

However, in their submission the applicants suggested that the following provisions in Chapter 8 should remain protected:

- the principles of the dispute resolution arrangements (clause 8.2.1), the availability of judicial review under those arrangements (clause 8.2.11) and the limitation of liability (clause 8.2.12);
- the Code change arrangements (clauses 8.3.1–8.3.12);
- the procedure for handling derogations (clauses 8.4.1–8.4.6);
- the enforcement procedures (clauses 8.5.1–8.5.9);
- NECA's monitoring and reporting requirements (clause 8.7.1); and
- the purpose and constitution of the System Reliability Panel (clause 8.8.1 and clause 8.8.2).

They argue that allowing these provisions to remain protected strikes a balance between the need for flexibility and for the Code to change and evolve to meet changing market conditions; against the quasi-statutory nature of the Code and the importance of guaranteeing certain essential safeguards for market participants, end use consumers and the general public.

TransGrid stated that the retention of many provisions of Chapter 8 as protected gives a level of regulatory certainty to the operation of the Code. Accordingly it did not support the removal of the protected provision status of Chapter 8.

At the pre-decision conference, Edison Mission Energy (EME) similarly argued that some of the Chapter 8 provisions, including the code change process, should remain protected provisions.

The Snowy Mountains Hydro-Electric Authority (SMHEA) argued, however, that assigning Chapter 8 protected status may obstruct the beneficial evolution of the Code. It proposed that a new category of 'restricted provision' be created, that the Code be amended to specify that changes to restricted provisions are automatically subject to clause 8.3.9, and that the Commission announce in advance that it will subject any submitted changes to the full review and consultation procedures applying to new applications for authorisation/approval.

The Energy Users Group (EUG) argued that leaving the code change process as a protected provision may limit its flexibility. It stated that it would prefer if the protected provisions were removed from the Code as they are likely to detract from the competitiveness and flexibility of the NEM, and could be misused by a jurisdiction to limit competition. It is particularly concerned that the access undertaking is a protected provision and the length of protection, to 2010, is far too long.

Similarly the BCA/EWG expressed strong concern at the Conference and in its supplementary submission that the protected provision status of the access undertaking could be construed in such a way that the jurisdictions could prevent the implementation of changes (such as those arising from the NECA review) for as long as 2010. These concerns were also raised by the ACA and Ampol.

Commission considerations

The Commission is concerned by any limitations to the flexibility of the Code in responding to the changing needs of the ESI and electricity consumers. Concern will arise if desirable changes to the Code may be prevented or delayed and as such significantly impact on the overall effectiveness or efficiency of the NEM.

The Commission believes there is a strong case that protected provisions limit the flexibility of the Code. The effect of making a clause a protected provision is that the ability of any party to effect a change is limited by the threshold requirement for unanimous agreement by all jurisdictions. To the extent that the protected clauses are those that would or should need to be changed quickly, these provisions seriously undermine the flexibility of the Code to respond to the changing environment.

The provisions dealing with the framework and the intent of the NEM, the basis for the Code's operation (clauses 1.3–1.6) and the commencement date of economic regulation of transmission revenue are acceptable. This is because these provisions form the foundations of the agreement between the jurisdictions to establish the NEM. The same reasoning applies to agreement on liability and it is reasonable that the jurisdictions, in joining the NEM, would want some say over security of supply to sensitive loads. Clause 1.12 stating that the NEM access code is to operate until 2010 satisfies the requirement that an access regime must have an expiry date.

In relation the concern that the protected provision status of clause 1.12 may have the effect of preventing change to the access code and access undertaking until 2010, the Commission considers that clause 1.12 operates only to protect the provision that:

- the Code sets out the terms and details of access arrangements; and
- the access code and access undertaking expire on 31 December 2010.

Therefore the provisions of the access code or access undertaking in the Code are not protected, and any changes, for example arising from the NECA review, will not be prevented by the protected provision status of clause 1.12 and implementation of change cannot be vetoed by any of the participating jurisdictions. The Commission believes that the value of VoLL (clause 3.9.4) must be reviewed yearly.

Setting the level of VoLL as a protected provision limits the Code's flexibility in maintaining an economically efficient value for the price cap,[34] and for this reason the protected provision status of VoLL must be removed. In response to the arguments of CitiPower and Eastern Energy, the Commission believes that having VoLL as a protected provision may in fact limit its ability to manage significant risks.

With respect to the protected provision status of Chapter 8, the Commission considers that there is generally the need for some flexibility in these arrangements, so as to allow for changes to occur quickly where gaps and inconsistencies become apparent. Accordingly, the Commission does not support all of Chapter 8 being a protected provision. The Commission, however, acknowledges that there are valid reasons why much of clauses 8.3, 8.4 and 8.5 should have protected provision status. The retention of provisions of Chapter 8 relating to

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[34] The price cap is discussed in section 8.6.

Code change arrangements, the procedure for handling derogations, and the enforcement procedures as protected gives a degree of regulatory certainty to the operation of the Code. These clauses are largely general principles for the administration of the Code. The Commission considers that making these clauses protected provisions guarantees certain safeguards for market participants. The Commission believes that the protected provision status of the access undertaking and the duration of the protected provisions similarly provide a degree of certainty to market participants.

Concerning SMHEA's suggestion that restricted provisions be created, the Commission is of the view that as the proposal would involve a fundamental change to the Code it has been submitted too late in the process of authorisation of the Code to warrant its serious consideration. In summary the Commission concludes that only a few provisions in the Code may be protected provisions, some of which are the fundamental building blocks of the Code. The Commission is of the view that no further clauses can be made protected provisions or that the current protected provisions be extended, otherwise the overall flexibility of the Code could be reduced and the public benefit diminished. Further the Commission requires that the protected provision status of much of Chapter 8 of the Code and clause 3.9.4 be removed, to increase the flexibility of the Code, and diminish the anti-competitive detriment of these provisions.

Conditions of authorisation

C6.1 No further provisions of the Code as currently drafted, or as amended from time to time, may be made protected provisions.

C6.2 Clause 8.3.1(a)(2) must be amended to provide that the only protected provisions of Chapter 8 are clauses 8.3.2 to 8.3.12, clause 8.4 and clause 8.5.

C6.3 Clause 3.9.4(e)(2) must be deleted.

6.2 Liability of administrative bodies

There are provisions throughout the Code which limit the liability of NEMMCO, system operators, NECA, and other administrative bodies and their agents and employees for acts or omissions performed in good faith. By signing on to the Code, Code participants agree to the condition that the liability of these bodies is limited to certain circumstances. The clauses dealing with liability are summarised below.

Liability of the administrative bodies.

- Clause 3.2.9 — neither NEMMCO nor system operators are liable if they acted in good faith (this is a protected provision).
- Clauses 5.9.4(a) and (b) — Neither NEMMCO nor a Network Service Provider (NSP) is liable for loss or damage due to disconnection under clause 8.5.6.
- Clause 8.5.8(d) — no action is available against NECA or its agents if publication of reports on matters that have gone before the National Electricity Tribunal is made in good faith.

- Clause 8.7.3(b) — NECA is not liable if publication is made as part of its reporting obligations with respect to enforcement or monitoring. However, NECA must use all reasonable endeavours to ensure the information is disclosed only in a manner and to the extent which protects the confidential nature of the information.

Liability of officers, staff, agents and contractors.

- Articles of Association, NEMMCO clause 11.3, NECA clause 12.5 — NEMMCO and NECA may obtain insurance for an officer, auditor or agent of the company or of a related body corporate.

- Clause 3.19.2 — None of NEMMCO's staff, agents or contractors is to be liable in contract or tort for any loss or damage from the use of any computer software to operate the market.

- Clause 8.2.12 — To the extent permitted by law, the Dispute Resolution Adviser (Adviser), the Dispute Resolution Panel (DRP) and its members and any body appointed by the Adviser, or member of that body, are not to be liable for any act or omission done in good faith.

- Clause 8.3.12 — Neither the Code Change Panel (CCP) nor its members are to be liable in any way for any change made to the Code.

Liability of Code participants to NEMMCO and NECA.

- Clause 8.6.5 — Each Code participant indemnifies NECA and NEMMCO for any breach of the confidentiality provisions in clause 8.6 by that Code participant or any officer, agent or employee of that Code participant.

In addition, the Code makes compensation arrangements for generators and market customers where scheduling errors occur, [35] but NEMMCO is not liable for this except out of the Participant Compensation Fund (PCF).[36] The PCF is comprised of that component of participant fees that is attributable to the Fund. The compensation payable is limited to the funds available in the PCF in a given year (see clause 3.18.2 for details).

Issues for the Commission

Limiting the liability of NEMMCO, administrative bodies and their employees, agents and contractors may constitute a barrier to market entry due to the cost of increased risk or the cost to market participants of private insurance cover. The issue is whether the costs associated with requiring NEMMCO to insure itself for its actions (a cost that will be borne collectively by all market participants and ultimately end use consumers) are less than the costs of market participants individually having to bear that risk themselves.

Also, there is the issue of whether limiting the liability of NEMMCO, administrative bodies and their employees and agents affects their behaviour in a way that makes the market less efficient. That is, whether there is a moral hazard in having liability limited to certain circumstances.

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[35] A failure by NEMMCO to follow the central dispatch process in accordance with the market rules.

[36] Clause 3.18.2(h).

A further issue is that the imposition of contributions to the PCF on market participants and the limitations on compensation from the PCF may be provisions that have the purpose or effect of substantially lessening competition by creating a barrier to entry which may exclude some potential participants.

What the interested parties say

The SMHEA expresses the view that NEMMCO should be liable for its and its agents' actions and compensation should be paid out of a trust fund.

Macquarie Generation is concerned that NEMMCO is not liable for possible financial loss that it may cause to a participant by its actions. It states some mechanism should exist to ensure NEMMCO accepts some of this liability even if it is limited.

Several interested parties are concerned with the effect of the PCF.

The Victorian DBs cannot envisage any circumstances in which they will be able to claim compensation from the PCF given that the spot price cannot change under the Code. They consider that only generators should contribute to the fund, rather than all market participants.

Integral Energy believes that the title of the PCF is ambiguous and raises the entry barrier for smaller participants. It feels that the PCF is more a generators/dispatch compensation fund and, as such, the financing of the PCF should be sourced from participants who stand to receive compensation for scheduling errors. It states the requirement that all market participants are to pay out of their pool fees their contribution to the PCF could pose a serious barrier to entry for smaller pool participants and an added financial burden which limits sustainable participation in the market.

EnergyAustralia states that the PCF is only warranted to compensate participants when NEMMCO has made a mistake in administering the market. It submits that it is important that sufficient drivers are imposed on NEMMCO to prevent such errors and minimise their effect if they do occur. EnergyAustralia argues that since there is no provision to recalculate the spot price the only recourse for compensation due to scheduling errors appears to be through the PCF. It suggests that the wording is thus very slanted towards the generation (supply) side of the market and does not appear to envisage market customers claiming against the PCF (except in the rare case of dispatchable load being incorrectly scheduled). It recommends that the PCF be renamed the 'Scheduling Error Fund'. It argues that to pay artificially inflated spot prices and then ask retailers to contribute into a PCF which only (or predominantly) compensates generators is untenable. EnergyAustralia thus requests that either generators only contribute and compensate each other in the event of scheduling errors, or all market participants contribute to the PCF and are all entitled to claim compensation. Furthermore, it argues that the compensation guidelines outlined in clause 3.18.2 are vague and there needs to be considerably more detail outlining the DRP's process for determining whether compensation is necessary and its level (if any).

Delta Electricity is concerned that clause 3.19.2 would be interpreted to include scheduling errors. It considers that NEMMCO should be liable for scheduling errors and market participants should have a right to sue NEMMCO for compensation should such an error occur and it is shown that NEMMCO did not act in good faith. Further, Delta Electricity argues that a PCF is not considered an efficient mechanism and that it is inappropriate that NEMMCO operates a PCF.

Delta Electricity concludes that errors in the scheduling of dispatchable generators and loads should be absorbed by each participant so affected, based on the assumptions that errors occur infrequently, that they affect pool participants in a random pattern, and that NEMMCO is protected from liability for such errors. It is considered that over time it is likely that all generators will share in the losses and gains from this arrangement and that it is also probable that the increased level of accountability placed on NEMMCO will create an environment where errors are infrequent.

What the applicants say

The applicants note that if NEMMCO were to be liable for its actions it would need to be established with a significant capital base. They argue that this is clearly not desirable as NEMMCO's only source of income is from market participants.

Issues arising from the draft determination

In the draft determination, the Commission outlined the following condition of authorisation concerning the liability of administrative bodies:

C6.4 Clauses 3.18.1 and 2.12 must be amended to state that only scheduled generators will pay the fees that NEMMCO allocates to the Participant Compensation Fund.

At the pre-decision conference, the applicants accepted the Commission's arguments regarding the PCF, and agreed with the condition of authorisation, that only scheduled generators should pay into the PCF.

Energy Brix, Loy Yang Power, Southern Hydro, EME and the incumbent Victorian generators claimed that generators should not pay the fees into the PCF. They argued that the scheduling function is performed on behalf of customers and that scheduling errors are a failure of NEMMCO in purchasing for customers, and that customers should therefore fund compensation for the errors. Further, the generators cannot influence the outcome of scheduling other than by their bidding and therefore should not be required to bear the brunt of errors by the provider of the scheduling service, ie NEMMCO. Pacific Power, Hazelwood Power, EME and Delta Electricity argued that if only scheduled generators are to pay into the PCF then it should only be used to compensate scheduling errors for generators.

United Energy supported the Commission's condition of authorisation.

Commission considerations

The actions of NEMMCO in, for example controlling and co-ordinating power system security, calculating the dispatch of generators and performing the settlements function, and of NECA and other bodies in performing their functions under the Code, involve some risk of error which may cause loss to market participants. The Commission is concerned that liability for actions is limited to specific circumstances and that the level of any compensation may be limited or unavailable, as this may discourage market entry or affect market efficiency.

Limited liability of administrative bodies

The Commission generally takes the view that liability should not be limited. However, there may be a public benefit in limiting liability if significant trade-offs can be identified.

NEMMCO and NECA (including their related administrative bodies) are funded by market participants and are operated on a cost recovery basis (not-for-profit corporations). Thus, it could be argued that, if they were to assume full liability for actions under the Code, any payments for claims made against them or any costs incurred in having to insure against such claims will be reflected in higher participant fees to cover this risk, which may deter entry of smaller participants. This cost may ultimately be passed through as higher end user charges.

Conversely, limiting liability for errors shifts the balance of risk to each participant which will impose a cost in the form of them having to cover any loss if errors occur or of private insurance to cover potential loss. As such this may again deter market entry, particularly for smaller participants, and the cost may be passed on to end users.

Thus, barriers to market entry could exist whether liability is limited or not. On balance the Commission considers that limiting the liability of NECA, NEMMCO, etc. for losses due to errors is more appropriate, particularly as the likelihood of losses occurring is considered by the applicants to be low. Furthermore, given that NECA and NEMMCO are limited by guarantee companies it may be more suitable for individual market participants to carry any risks.

Moral hazard

The Commission is concerned that limited liability may mean that the administrative bodies will fail to meet the standard of care which would be required of them if their liability was not limited. That is, there is moral hazard which may create perverse incentives which result in a reduced public benefit. This occurs where, due to immunity from liability, the companies do not take due care. If this was the case market participants and ultimately end use consumers may face greater costs in order to insure themselves against the possibility of errors on the part of NEMMCO, NECA, etc. However, it is recognised that a reasonable standard of care is always legally required of them and that there is the constraint of having to act in good faith. Alternatively, if liability was unlimited, this may lead to overly cautious risk management resulting in a less efficient market.

Thus, the Commission believes that the limiting of liability for errors does not appear to have disadvantageous effects on the bodies' actions.

Participant compensation fund

The Commission is concerned that higher participant fees to cover the PCF and the fact that compensation is limited could mean that the provisions may act as a barrier to entry. There is also concern that, although all market participants pay higher participant fees to cover the PCF, only scheduled generators are likely to receive compensation.

The Commission considers that by spreading the costs of liability for scheduling errors, costs to generators are reduced and this may be passed on in terms of cheaper generation prices. However, the limited size of the PCF means that it is unlikely to provide a great benefit to large participants although it might be useful to smaller ones.

The Commission is not convinced of the value of keeping the PCF in the form envisaged in the Code. On the basis of the arguments against the PCF the Commission considers that since it is limited to scheduling errors only generators who are centrally dispatched should pay into the PCF and receive compensation from it.

Summary

The decision to limit NEMMCO's liability has been made by the participating jurisdictions. The Commission endorses this decision at this point in time — where the market is evolving and is in a learning phase and where there is no significant capital base from which to pay compensation. The Commission considers that it is possible for financial barriers to entry to arise whether market participants or the administrative bodies bear the loss, and that limiting liability may provide effective risk management incentives. Therefore, the Commission considers that the public benefits of the liability provisions outweigh any detriment.

The Commission notes Western Power's opinion that the liability references in Chapters 4, 5 and 7 seem inappropriately located and that consideration should be given to removing these clauses into a separate chapter of the Code. The Commission's view is that user guides (which are to be developed) could be an instrument for summarising liability.

Condition of authorisation

C6.4 Clauses 3.18.1 and 2.12 must be amended to provide that:

(a) only scheduled generators can be required to pay the fees that NEMMCO allocates to the Participant Compensation Fund; and

(b) only scheduled generators who are centrally dispatched are entitled to receive compensation from the Participant Compensation Fund.

6.3 Code complexity

The Code is a lengthy and complex document. This may be justified given the technical nature of the processes covered in the Code and the comprehensive range of reforms it seeks to encompass.

Issues for the Commission

The Commission must consider whether the complexity of the Code, which may discourage entry into the NEM and thereby restrict competition in the electricity industry, is outweighed by the public benefits of having a comprehensive and accurate Code.

What the interested parties say

Submissions received by the Commission note that the Code may discourage entry into the NEM, particularly for smaller participants, because of its length and level of detail.

Integral Energy claims that the Code is too wordy, too long and too complex but acknowledges that the system security, connection, network pricing and metering processes, covered in Chapters 4, 5, 6 and 7 of the Code, are all required for a competitive electricity market and are themselves complex. Integral Energy notes that many of these processes have always been complex and that it is only now, when the opportunity has been taken to document all issues, that everyone has been able to see the extent of the detail.

The Australian Chamber of Commerce and Industry (ACCI) submits that the Code appears to be less complex, interventionist and prescriptive than the earlier working drafts. However, the ACCI is concerned that engineering regulation may become an unwarranted barrier to entry and participation, or an unnecessary impediment to competition in the NEM.

Macquarie Bank has fundamental concerns with the complexity of the Code. It cites clause 1.4 which states that it is intended the Code "provide a regime of 'light handed' regulation of the market to achieve the market objectives" and says that the complexity of the Code is fundamentally at odds with that objective. It believes that the current form of the Code proposes an environment which is overly complicated and unnecessary.

Northparkes Mines argues that the Code has been structured to fulfil technical rather than commercial considerations. It contends that it would be preferable to see the subdivision of Code requirements: a dissection of commercial and technical obligations and rights.

The Business Council of Australia (BCA) submits that the volume of relevant documentation and its complexity stands in stark contrast to the Gas Code. It says the Gas Code runs to less than 70 pages and by comparison with the Code is pro-competitive, clearer and less prescriptive. The BCA favours the Gas Code's general approach over that adopted by the ESI.

In addition, both the BCA and Australian Paper are concerned that complexity may inhibit the emergence of competition, protect the existing incumbents in the industry, and allow the exercise of market power by the supply side of the industry. The BCA contends that its member companies have been thwarted in their negotiations with utilities due to the complexity of the Code.

The National Farmers Federation (NFF) contends that the Code should be made more 'user friendly' and supports user guides. The EUG also favours further simplifications to the Code. It states that no matter how useful the user guides are from a practical point of view, they will not have the legally binding force of the Code. The BCA believes that the present Code needs to be substantially simplified and modified before it can be authorised by the Commission. It submits that 'the devil is in the detail' and it is necessary to be assured that the details do not mislead or contain hidden problems which may be anti-competitive, increase transaction costs and cause problems in the future.

The Australian Chamber of Manufactures (ACM) suggests that the Code's complexity means that users will have difficulty in making comments to the regulator. Australian Paper argues that the Code's complexity can be used to confound the regulator.

What the applicants say

The applicants agree that the Code is a complex document but note that:

- much of the Code is not relevant to most participants in the market, for example the Code sets out specialised instructions for generators and NSPs;
- the Code standardises and documents information and technical requirements that have, in the past, operated as good industry practice;
- specification of responsibilities and obligations is a by-product of the industry reform and restructuring, and will have the effect of encouraging private sector participation; and

- the Code reduces information asymmetries between new and established participants.

The applicants propose to develop indexes, handbooks and user manuals to ensure the Code is accessible and more user friendly. The Commission has been informed that these manuals are currently being prepared.

Issues arising from the draft determination

The ACA strongly argued for embedded generation guides particularly for connection, standby and avoided network guides. The ACA added that NECA had been slow off the mark in producing these guides and had not consulted the ACA.

Integral Energy was concerned that the Code has become all-encompassing in that it has sought to cover both physical market and financial market outcomes. It accordingly welcomed the Commission's decision to delete the provisions relating to the STFM and IRH market as conditions of authorisation.

Commission considerations

The length and complexity of the Code can be explained, in part, by the comprehensive range of reforms it encompasses which are aimed at establishing a competitive interconnected electricity market. The Code also represents a national integration of existing engineering, administrative and operational requirements which are in use in each State.

The Commission notes the BCA's argument that the approach of the Gas Code is to be preferred to the approach taken in the National Electricity Code. However, the Commission is of the view that the Gas Code may be regarded as a regulator's handbook, not a detailed guide for industry participants. The Gas Code contains no technical requirements, nor does it set up regulatory or administrative regimes, or make provision for a spot market. These matters are to be the subject of a further technical code, an intergovernmental agreement and proposals by the jurisdictions and market participants. Hence, the Commission considers a valid comparison between the Gas Code and the National Electricity Code cannot be drawn.

The Commission recognises that it is not reasonable to assume all persons will be able to immediately understand all the rights, obligations and standards which the Code requires. However, the Commission is also concerned that any attempts to simplify the Code may alter its meaning and lead to inaccuracies or ambiguities.

There is therefore a strong argument for streamlining the Code to avoid unnecessarily complex language and undue prescription and complexity. The Commission agrees with Western Power's suggestions relating to complexity, ease of use and readability of the Code, particularly in relation to the removal of extremely long sentences, and the addition of diagrams where necessary. The Commission has forwarded these recommendations to the applicants for their consideration.

The Commission also supports the proposal of NECA to develop a series of Code user guides for the following reasons:

- appropriately developed user guides will be able to succinctly explain the rights and obligations of market participants under the Code as well as set out supplementary diagrams relating to processes; and

- user guides can help overcome problems of complexity.

The Commission considers that these guides should be developed prior to NEM commencement. However, the Commission cautions that user guides should not be relied on as a substitute for reading the Code — they should be viewed only as guides to aid understanding and interpretation.

Further, as the Code is likely to be an evolving document the Code change process, discussed in section 13.2, goes some way to providing an opportunity for refinement to the Code.

The Commission recognises that due to the range of reforms it seeks to encompass the Code is a lengthy and complex document. However, the Commission considers that the benefits from explicit documentation of standards, technical requirements, and the rights and obligations of Code participants outweigh any anti-competitive detriment arising out of the Code's complexity.

6.4 Market design

Trading in the NEM will be through a gross pool, with NEMMCO as a counter party to all trades. In a gross pool all electricity is traded by auction at a common clearing price through the pool. The decision to dispatch is centrally co-ordinated, and all trading is blind in that the buyer does not know the identity of the specific seller.

The pool design adopted for the NEM has been endorsed by the participating jurisdictions. However, there has been considerable debate on the costs and benefits of this design, and its pros and cons in comparison with a net pool arrangement.

In a net pool arrangement physical energy contracts are negotiated directly between generators and customers, and the system operator manages energy flows throughout the network in accordance with contractual obligations and activity in the net pool market for contract differences.

Issue for the Commission

The issue for the Commission is that the gross pool design is responsible for the wholesale arrangements containing breaches of the TPA particularly in regard to exclusive dealing, as identified by the applicants.

Issues arising from the draft determination

Some participants reiterated their positions with regard to the market design, but no new issues of substance were raised at the pre-decision conference or in subsequent submissions on the merits of the NEM pool design.

Commission considerations

The efficiency advantages of a gross pool trading system, compared to the alternative of bilateral contract trading supplemented by a net spot market for trade in contract differences, have been emphasised as the primary reason for adopting a gross pool design. Specifically, a suitably structured gross pool can efficiently price the external third party effects of transport losses and the costs of network constraints that arise in a shared network with many buyers and sellers. A gross pool design was supported by a number of submissions to the Commission's issues paper (March 1996).[37]

In contrast, losses and the cost of network constraints become market externalities in a bilateral contracting/net pool system, and can be complex and costly to internalise by way of compensatory payments between large numbers of market participants. Centralised management of all electricity flows across the network would still be required to identify and quantify the third party costs that result from individual bilateral transactions. Therefore, a gross pool design is a means of ensuring that all such externalities of shared network trading can be more readily identified, accounted for and efficiently priced.

Some submissions to the issues paper expressed concerns about the requirement that all energy be traded through a gross pool and argued strongly for a trading system based on bilateral contracts and a net pool.[38] The BCA expressed similar views in its NEM submission. However, a gross pool trading system also allows opportunities for a wide range of bilateral contracts between generators and electricity users which can insulate parties from fluctuations in the spot price determined in the gross pool.

While acknowledging that a gross pool design internalises externalities, critics of the gross pool design are concerned with the supply side dominance of the market, and the limited scope for demand side factors to influence the spot price. That is, there is concern that strategic bidding behaviour by generators is likely to result in higher spot market prices, on average, than would be expected to result from a less concentrated supply side market structure. It is argued that the shortcomings in the market arrangements and the gross pool design will impose constraints on the ability of electricity users to moderate the resulting price effects of these supply side factors in either the spot market or the financial hedge market. In addition, it is argued that the gross pool design will limit the scope for individual buyers, as well as buyers in aggregate, to bring demand side factors to bear.

Fundamentally, concerns over market power at the outset of the NEM arise from market structure issues. These concerns are acknowledged by the Commission and are discussed in more detail in section 5. However, if market power is exercised it should affect the price of electricity under both a net and a gross pool. Some large energy users may have countervailing market power that could be exercised in either physical or financial bilateral contracting, but again this countervailing power could be exercised under both market designs.

Only if it can be shown that supply side market power is enhanced in some way by the gross pool arrangements set out in the Code, or that the net pool necessarily addresses the supply side market power issue more effectively than the gross pool, would the gross pool option be open to some question. The Commission considers that there is not sufficient evidence that this is the case.

[37] The Electricity Sector Reform Unit (South Australia), TransGrid, SMHEA, and the Victorian Government.
[38] ACA, BCA, and Visy Paper.

There would also appear to be a number of options available to provide countervailing pressures on the supply side in the NEM which were not present in previous State based markets, such as:

- electricity users can elect in advance to turn off switchable blocks of load at particular spot prices, thus saving money by reducing consumption and having some demand side influence on the spot price for their remaining load;
- the availability of the bilateral financial contracts market enables customers to determine with greater certainty the price they will pay to generators irrespective of fluctuations in the spot price; and
- the threat of entry and regulation arising from the abuse of market power.

As the market matures it is likely to become more responsive to demand, and demand side options will develop over time if the market incentives are such that their development is warranted.

In summary the Commission is not convinced that a net pool would provide greater public benefits than the gross pool arrangement proposed for the NEM. Accordingly, the Commission is not convinced that the NEM's gross pool design requires alteration.

7. Code participants and registration

Chapter 2 of the Code applies to all Code participants. It sets out and describes the various categories of Code participants and registration procedures. It also sets out the fees payable by Code participants.

7.1 Eligibility

Clauses 2.2 to 2.7 set out the Code participant categories and requirements which a person must satisfy in order to become registered. All persons who wish to participate in the market must register with NEMMCO as Code participants, and in so doing become bound by the Code. A person who satisfies the criteria for a generator or an NSP must register with NEMMCO unless the person obtains an exemption. Registration in the other categories of Code participant is voluntary.

Basically, in the NEM there are the following categories of Code participants:

- market participant, which refers to a person registered with NEMMCO as a:
  - market customer, such as retailers;
  - trader, who trades in financial contracts associated with the STFM and/or in the IRH market; or
  - market generator;
- NSP, providing the services of either a distribution or transmission system connected to the national grid;
- special participant, which refers to the system operator or the distribution system operator; and
- NEMMCO.

To be eligible for registration under any market participant category a person must satisfy the Code's prudential requirements and meet any relevant requirements imposed by its jurisdictional regulator (clause 2.5.2).

In April 1997 the Code was amended to provide that clause 2.2.5(a) classifies a non-market generating unit as 'a generating unit from which the sent out electricity is purchased in its entirety by the local retailer or by a customer located at the same connection point'. Prior to this amendment a generating unit was a non-market generating unit 'if the sent out electricity is purchased in its entirety by the local retailer or by another Code participant, in the latter case, where the purchase occurs at the same connection point.'

Scheduled generators

The Code provides that unless otherwise approved by NEMMCO, generators with a capacity of 30MW or greater are classified as scheduled generating units (clause 2.2.2). Such generators are obliged to participate in the central dispatch process.

Issues for the Commission

In terms of the TPA these eligibility requirements could be considered to be:

- exclusionary provisions, as competing participants agree not to trade with unregistered persons;
- exclusive dealing provisions, as participants in the market agree to trade on condition that they will not supply electricity to, or acquire electricity from, unregistered persons; or
- provisions having the purpose or effect of substantially lessening competition, as the requirement to be registered before being entitled to trade might act as a barrier to entry to the relevant market.

What the applicants say

The applicants argue that although registration requirements may lessen competition by restricting participation in the market, they are an essential element for the orderly functioning of the NEM and are justified on the grounds of the substantial public benefits that arise.

Furthermore, the applicants argue that generators and NSPs need to be bound to the Code in order to preserve the integrity of the power system and ensure public safety.

The applicants claim therefore that compulsory registration of market participants achieves the binding effect of the Code and is also necessary for the adequate functioning of the gross pool market design.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C7.1 NECA must re-define a non-market generator (clause 2.2.5(a)), in the light of the concerns raised by interested parties, using the Code consultation procedures, prior to commencement of the NEM.

At the pre-decision conference, and in its subsequent submission, the ACA sought clarification with the interpretation of the terms *connection point* and *sent out*, as used in clause 2.2.5(a) to define a non-market generator. It argued that a non-market generator should be defined to include generators that sell their output only via a distribution system (for example some embedded generation may be able to sell output to nearby end use consumers via the local distribution system), and should be classified as non-market generators. The applicants' submission in response to the draft determination states that they are prepared to clarify clause 2.2.5(a) but the concerns of interested parties, such as the ACA, may not be addressed as non-market generators are only those that do not sell any of their output via a distribution or transmission system. The applicants state that the market proposals are for a gross pool arrangement and bypass of the pool is not permitted if trading is beyond the generator's local connection point.

At the pre-decision conference the BCA/EWG raised the issue of the relative merits of gross and net pools, strongly reiterating its position that bilateral physical contracts with dispatch rights must be allowed.

Scheduled generators

BCA/EWG argued that there should be more flexibility in Chapter 2 for exemptions to be granted for mandatory participation in the spot market. In its subsequent submission the BCA/EWG suggests that a case could be made for a 100MW threshold, rather than the current threshold of 30MW. Further, it argues that the threshold should refer to sent out electricity rather than the nameplate rating. It also notes that the exemption mechanism in Chapter 2 of the Code needs to be strengthened and should include some arbitration provisions, possibly appeal rights to the Commission, if NEMMCO disallows an exemption application.

The ACA reiterates its position regarding guaranteed dispatch rights for the portion of electricity required to generate steam for thermal host cogeneration plant. It notes that the Commission appears to have accepted the arguments for allowing exemptions to Code provisions with regard to incumbent generators (technical derogations) and it is inconsistent to impose the costs required on cogeneration plant to install the back-up facilities required if cogeneration plant is not guaranteed dispatch.

The ACA also argues that the 30MW threshold, if it applies to system security of the transmission system (as stated by the applicants at the pre-decision conference), should not therefore apply to embedded generation, connected to the distribution system. It suggests that the threshold should be at least 50MW, and NEMMCO should publish guidelines regarding exemption granted under Chapter 2 of the Code.

The EUG argues that the 30MW threshold should be raised to at least 50MW, with generators being required to notify NEMMCO of daily output, but not subject to dispatch arrangements. Further NEMMCO should be flexible with regard to exemptions, especially to ensure that entry to the market by smaller generators is not hindered.

Both the EUG and the ACA note that small scale generation can impose an important competitive discipline upon large incumbent generators.

Pacific Power state that the current 30MW level of exemption is appropriate in terms of equity with existing players and from the viewpoint of system security.

NEMMCO stated that the 30MW limit needs to be viewed from system security (NEMMCO needs to control loading on transmission lines) and economic perspectives. Clause 2.2.1 (c) gives NEMMCO the ability to develop guidelines on exemptions. NEMMCO argues that as long as this clause is there, the BCA/EWG's concerns should be allayed.

Commission considerations

The Commission acknowledges that the majority of eligibility provisions outlined in the Code assist in the orderly functioning of the market and therefore deliver considerable public benefits. The registration of Code participants helps achieve the binding effect of the Code, and accordingly contributes towards preserving the integrity of the power system. Concerns, however, have been raised with four aspects of the eligibility provisions.

Non-market generating unit

The EUG argues that the amendment to clause 2.2.5(a) could restrict the ability of non-scheduled generators to determine how they sell output, in which case it would be anti-competitive. United Energy raised similar concerns. The EUG adds that the impact of this proposal should be carefully assessed, and the applicants asked to justify it. This issue was also raised at the pre-decision conference and in subsequent submissions to the Commission.

The Commission agrees that some ambiguity may exist with the clause and has asked that the applicants review the clause. However, the Commission also notes and supports the applicants response to the draft determination, which states that a non-market generator is one that sells all of its output at the local connection point to a local retailer, customer or Code participant. That is it does not enter the pool and will not be settled via the NEM. Specifically if any of a generator's output is sold via the distribution or transmission network then the generator must be a market generator. To do otherwise would be to allow bypass of the pool.

Connection points

Clause 2.3.1(b) of the Code requires a customer to classify its purchase of electricity at a connection point as either a first tier load, a second-tier load, a market load, or an intending load. As highlighted by Alcoa of Australia, this clause implies that a purchase at a particular connection point cannot be classified as partly a market load and partly something else, such as second-tier load. Alcoa states that the Code would appear to require customers to make an all or nothing exclusive election with respect to their purchase arrangements thereby preventing them from taking full advantage of the competitive market at that connection point. Whilst appreciating Alcoa's concerns the Commission understands that Alcoa's proposal is not technically feasible. The Commission has been informed that it is not possible to separately meter what is bought from the pool and what is bought from another retailer at the same connection point.

Scheduled generators

The EUG argues that the mandatory spot market disadvantages embedded generators over 30MW capacity who will generally need to participate in central dispatch and meet the associated costs, notwithstanding their 'must run' status. It adds that this cut off is bound to be somewhat arbitrary and should be monitored for its impact on competition in generation, along with NEMMCO's powers to provide exemptions. The ACA argues that the NEM could follow the approach taken in the England/Wales market, which has a 50MW threshold for central dispatch, rising to 100MW by 1998.

These arguments were reiterated and further developed at the pre-decision conference and in subsequent submissions by the EUG, ACA and BCA/EWG. In particular NEMMCO's power to grant exemptions was seen as somewhat arbitrary and it was argued that strong and reasonable guidelines should be developed. It was also noted that this provision may have the effect of imposing costs upon embedded generation so that they can participate in the market and meet Code requirements. This was seen to be in contrast to the technical derogations of the incumbent generators that are supported on the grounds that it would be unnecessarily onerous to expect them to meet the costs of upgrading to meet existing Code standards.

The Commission accepts the applicants statement that the 30MW threshold for scheduled generators is necessary from a systems security perspective as it attempts to ensure that any generator who can have an impact on system security is bound by the Code. Further, the Commission notes that the Code sets out the circumstances under which NEMMCO may classify a generating unit of greater than 30MW as a non-scheduled generator, and such a decision is subject to review by the National Electricity Tribunal. The Commission considers, that NECA should periodically monitor this clause to ascertain the impact it is having on entry to the market by small scale generation projects, and whether the threshold could be raised without threatening systems security. Further the Commission would support the development of guidelines detailing the exemption procedures and criteria, if such guidelines are seen to be necessary in the future.

Cogenerators

The ACA states that the central purpose of cogeneration plants is the continuous supply of heat (usually steam) for industrial or commercial processes which are dependent on that steam for operation and hence revenue. Generally, if the gas turbine shuts down because its electrical output is not required, then the supply of steam from the turbine's waste heat recovery boilers also shuts down. Accordingly, in the absence of back-up boilers the industrial process would also have to be shut down.

The ACA argues that, to remove an anti-competitive bias against cogeneration, for the purposes of negative bidding, cogenerators should be able to net off from their bids the 30MW threshold, plus any additional electrical capacity required to remain on-line to supply the minimum essential quantity of process steam, commensurately reducing the dispatched MW. The ACA further notes that the treatment of incumbent large scale generators and embedded generators is inconsistent to the extent that the large scale generators have derogated from the Code where the costs of complying with the Code are unnecessary or uneconomical.

The Commission appreciates the concerns expressed by cogenerators. The Commission, however, believes that to allow cogenerators to 'net off' is a form of positive discrimination in their favour. All generators have inflexibilities that they must face in periods of excess generation.[39] Accordingly, the Commission sees no valid reason for allowing cogenerators an advantage because of their steam/heat requirements. The Commission notes the ACA has concerns regarding the treatment of embedded generation compared to large incumbent generators, in respect to compliance with the technical provisions of the Code. The Commission has not altered the condition of authorisation imposed in the draft determination regarding the technical derogations — that is they must end by 31 December 2002. However, the Commission notes some generators may seek technical derogations through the provisions under Chapter 8 of the Code, and such derogations may in effect be permanent derogations. It is therefore up to the embedded generators to avail themselves of the Chapter 8 processes of the Code, as other generators must do, if they can substantiate their claim for a derogation from the Code.

Overall assessment

The Commission sees entry conditions imposed by the Code as a determining factor in the level of contestability in the NEM and, as a consequence, the magnitude of price benefits which may be passed on to consumers. The Commission considers that the majority of eligibility requirements outlined in the Code assist in the orderly functioning of the market.

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[39] Excess generation issues are discussed in section 8.7.

However the Commission is of the view that different eligibility conditions in each jurisdiction may create barriers to entry into the NEM.[40]

Condition of authorisation

C7.1 Clause 2.2.5 must be amended to provide clearly and specifically, with regard to where, how and to whom output must be sold, the circumstances in which a generator may be classified as a non-market generator.

7.2 Participant fees

Participant fees are designed to recover the operating expenses of NECA and NEMMCO, both of whom are non-profit organisations. Participant fees are payable by market and Code participants. NEMMCO must liaise with NECA and prepare and publish, before the beginning of each financial year, a budget of the revenue requirements for NEMMCO and NECA for that financial year, taking into account all of the factors referred to in clause 2.13.3(b).

NEMMCO is to establish the Code funds[41] set out in Table 1.1 of the Code along with the administration and registration fund, and the PCF. The NEL allows money in a Code fund to be invested and the earnings credited to that Code fund. Each of the Code funds may be supplemented with income from the registration and administration fund (clause 1.11(c)(2)).

Issues for the Commission

Participant fees may represent a barrier to entry particularly for smaller participants, or prohibit their effective participation in the market. Thus participant fees may represent a provision that has the purpose or effect (or likely effect) of substantially lessening competition in the market, and hence may result in a breach of s. 45 of the TPA.

What the interested parties say

The EUG supports the principles to be used to set charges. However, it is concerned about the current lack of specificity in the setting of pool fees and charges and control over these. It further states that fees should not be used to discourage entry into the market.

Boral Energy is concerned that the definition of non-market generators may open the way for generators to operate outside the pool and avoid fees.

What the applicants say

The applicants note that the principles to guide NEMMCO in the establishment of participant fees are set out in the Code. They also draw attention to the fact that both NEMMCO and NECA under their members agreements are required to provide services to Code participants on a cost effective basis.

The applicants admit that participant fees may lessen competition by creating a barrier to entry. However, they argue that the market cannot function without the key central co-ordination functions of NEMMCO and NECA and as such require a suitable fee structure to cover their operating costs. They state that NEMMCO and NECA provide services to the

[40] These concerns are discussed in section 5.
[41] The funds are for the STFM, IRHs, ancillary services and reserve trading.

market as a whole, which benefit all participants (a 'common good'), however, unless these fees are an obligatory part of participating in the market, participants could 'free ride' on these services. They believe that, provided the fees reflect the costs of providing NEMMCO and NECA services, any barrier to entry imposed cannot be viewed as artificial or discriminatory. They state that, on balance, the benefits of a well functioning, centrally co-ordinated market far outweigh the possible reduction in competition that the market fees of NEMMCO and NECA may present.

Commission considerations

Participant fees charged by NEMMCO are designed to recover the cost of providing common services such as operating the market and maintaining power system security, and to recover costs which cannot reasonably be allocated on a user pays basis. In addition, fees are set to recover NECA's operational expenses, where NECA also provides a service for the operation of the market. As such the Commission accepts that the charging of participant fees is essential to the operation of the market because of the common good properties associated with the services provided by NEMMCO and NECA.

The primary concern for the Commission is that participant fees may act as a barrier to entry for potential new entrants and disadvantage smaller participants. In fact, the applicants acknowledge this in their submission. The extent to which fees act as a barrier to entry will depend upon the structure of fees.

However, the exact structure of participant fees is yet to be developed. That is, it is not known which fees will be fixed or variable, whether they will be dollars per participant, or dollars per MW of energy, or even whether fees will differ between regions. This means that in respect of this authorisation the Commission is only able to assess the principles and procedures for fee determination as stated in the Code.

The Code sets out principles that the structure of participant fees should be consistent with. These principles can be summarised as the need for simplicity, cost recovery, cost reflective, and non-discrimination. In the determination of the structure of fees NEMMCO is to publish the extent to which the structure complies with these principles, and consider other fee structures in existence which it thinks appropriate for comparison purposes (clause 2.12.1(d) and (e)).

The Code does not preclude NEMMCO's Code funds being cross-subsidised from the registration and administration fund (clause 1.11(c)(2)). The cross subsidisation of one function by another may be commercial practice. However, if Code participants are to be charged on a cost recovery and cost reflective basis, as stated in the principles of fee structure, then there is no case for cross subsidisation. Cross-subsidisation can lead to inefficiencies if it disguises the true cost of an activity. In fact optimal transparency would be achieved if each fee were associated with a fund and a function. It is accepted though that in some instances the cost of doing so may outweigh the benefits, and hence linking a fee with a fund may not always be efficient.

Clause 2.12.3 of the Code states that payments received by NEMMCO from scheduled generators in respect of an excess generation period in the previous financial year will become part of NEMMCO and NECA's budgeted revenue. The Commission believes that money accumulated during an excess generation period should be returned to customers, and the Code must be amended to reflect this.[42]

NECA expenses

The Commission accepts the administrative simplicity of funding NECA through the recovery of participant fees by NEMMCO, but notes that this may give rise to concerns about the independence of NECA. Transparency and simplicity would be achieved if a separate fee were attributed to NECA. Moreover this would also be consistent with the principles of the fee determination.

Input in the determination of fees

Given that certain Code participants are compulsory participants, they have an immediate concern in the efficient operation of the market. The Code requires (clause 2.12.1(a)) that NEMMCO must develop, review and publish, in consultation with NECA, Code participants and such other persons as NEMMCO thinks appropriate, the structure of participant fees for such periods as NEMMCO considers appropriate. It is the Commission's view that the Code consultation procedures in Chapter 8 should be applied to the determination of participant fees.[43] Although there is the potential for consultations to render participant fee determination time consuming, a public process would help to allay participant concerns regarding the potential anti-competitive effects arising from the structure of fees. The process by which new fees are to be introduced is not mentioned in the Code and should also be subject to the Code consultation procedures. Pacific Power, in their submission to the Commission, state that, in order for NECA to undertake its roles it needs to be adequately resourced. At present Pacific Power does not consider that NECA appears to be adequately resourced for its role.

The applicants indicated in their submission to the Commission that they accept the Commission's view with regard to fees, but note that under their Members' Agreements final responsibility for the budgets of NECA and NEMMCO will remain with the member jurisdictions.

In summary, considering that NEMMCO and NECA's roles are pivotal to the operation of the market the Commission is satisfied that on balance there is public benefit in setting participant fees to recover the cost of operating the market by NEMMCO and NECA.

Conditions of authorisation

C7.2 Clause 2.12.3(b)(8) must be deleted.

C7.3 Clause 2.12 must be amended to provide that NEMMCO must use the Code consultation procedures in the introduction and determination of participant fees.

C7.4 Clause 2.12 must be amended to provide that:

(a) NECA's budgeted revenue requirement for each financial year, including any shortfall or excess in NECA's requirements from the previous year, is

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[42] The issue of the floor price is discussed in section 8.7.
[43] Code consultation procedures are discussed in section 13.7.

prepared and published separately from NEMMCO's budgeted revenue requirement; and

(b) a separate charge is made to Code participants to meet NECA's requirements as published.

8. Market rules

Chapter 3 of the Code sets out the market rules which govern the operation of the NEM. The purpose of the market rules is to create an environment which promotes efficient, competitive and reliable wholesale electricity trading. Key provisions of Chapter 3 are analysed below.

8.1 Spot market prudential requirements

Prudential requirements are set out in clause 3.3 of the Code. They form part of the eligibility requirements to compete in the spot market and must be met by all market participants.

Of the market participants in the NEM, scheduled generators tend to have low prudential requirement levels, as they will be net suppliers to the spot market. Market customers will face higher prudential requirements, and the cost of these prudentials will reflect each customer's level of exposure in the spot market and a risk premium, to be negotiated with the supplier of the prudential guarantee.

Issues for the Commission

The provisions relating to prudential requirements may constitute a breach of the TPA because they entail:

- exclusionary provisions, in that competitors agree not to purchase electricity from or sell electricity to market participants unless they satisfy the prudential requirements;
- exclusive dealing provisions, as each participant trades on condition that they will not supply electricity to or acquire electricity from any person who does not satisfy such requirements; or
- provisions substantially lessening competition, if they create a barrier to entry in the electricity market.

What the interested parties say

The requirement in clauses 3.3.2 and 3.3.3 that a guarantor be either a bank under the supervision of the Reserve Bank of Australia and listed under Part 1 of the first schedule of the Banking Act with an acceptable credit rating or a government has been perceived as unnecessarily stringent. The Victorian DBs, Boral Energy, the EUG and energyAustralia claim that such prudential requirements are overly conservative. They argue that the NEM prudential requirements need to be broadened to allow alternative means for market participants to satisfy NEMMCO as to their credit worthiness.

The Victorian DBs argue that the definition of 'acceptable credit criteria' discriminates against non-government market participants. They are necessarily required to provide credit support whereas a government owned market participant may not. It is argued that this offends the spirit of competitive neutrality.

Delta Electricity, while supporting the Code's prudential requirements in general, argues that if a market generator also registers as a market customer, prudentials would have to be met in respect of both entities. It states that prudential requirements should only be applied to the net exposure of each single legal entity.

Concerns are raised in relation to clause 3.3.6(b), which requires credit support to be replaced within 24 hours in a situation where the credit support provider may have its credit rating downgraded to an unacceptable level. Both the Victorian DBs and energyAustralia claim that the time taken to establish replacement credit support is not insignificant, and a minimum of 10 business days must be adopted in the Code.

Similarly, the Victorian DBs claim that clause 3.3.4(c), which allows NEMMCO to alter the acceptable credit rating definition on 10 business days' notice, sets unreasonable demands on market participants. The Victorian DBs also call for the deletion of clause 3.3.10, which discusses credit support concentration risk levels, as they are of the view that this clause will lead to a situation where a market participant who is required to organise additional credit support quickly under other provisions of the Code may be denied access to certain financial institutions.

What the applicants say

The applicants argue that, given the characteristics of the proposed NEM, the obligation for market participants to satisfy prudential requirements as a condition of participation is essential for the efficient operation of the market and the financial protection of the suppliers to the market.

They submit that because the spot market is a 'blind market' it is not possible for suppliers to undertake the normal credit risk assessment of customers and set prices and/or terms of payment accordingly. They state that, for this reason, the centrally co-ordinated prudential requirements have been structured to effectively place each purchaser at a common level of creditworthiness to provide suppliers with an appropriate level of confidence in the NEM. Without this confidence the suppliers to the market would have no choice but to include a risk component in their prices for electricity to compensate for the reduced and uncertain credit quality of the unknown counterparty, thereby raising prices and reducing customer benefits.

The applicants consider that it is necessary to limit the method of providing collateral to unconditional bank guarantees, as credit ratings alone are not viewed as providing sufficient liquidity or surety, and even cash may not provide sufficient security in the event of insolvency. They note that any cost implied by the requirement to provide guarantees is not a new cost imposed only for this market. All sales of goods involve a cost to cover the credit risk exposure of the counterparty to the transaction. The nature of the spot market requires a known credit risk level to be set which suppliers can price around. It is asserted that the requirement for guarantees passes the costing of this credit risk to the banking sector, where this pricing forms a major part of its commercial practice and should, therefore, result in the best possible pricing for the cost of the credit risk.

The applicants contend that the proposed arrangements do not discriminate in any way. The maximum credit limit and amount of the required guarantee will be determined by NEMMCO for each participant by a consistent methodology to be developed and published by NEMMCO. The size and cost of a guarantee, therefore, will be dependent on the way in which the market participant operates and trades in the market and the overall assessment of its credit worthiness by the provider of the guarantee. In addition, where guarantees are provided by a participating jurisdiction to a market participant, the participating jurisdictions have agreed to provide the guarantee on a commercial basis in accordance with agreed competitive neutrality provisions of the National Competition Principles Agreement.

The applicants consider, therefore, the method of calculating prudential requirements is a reasonable balance between the necessity to cover potential defaults without raising unnecessary entry barriers.

Issues arising from the draft determination

In the draft determination, the Commission imposed four conditions of authorisation concerning the Code's spot market prudential requirements:

C8.1 (i) Clause 3.3.3(a)(2) must be deleted;

(ii) Clause 3.3.4(c) must be amended so that the date of effect of a variation in NEMMCO's determination of an acceptance credit rating is not earlier than 30 business days after the date of notification;

(iii) Clause 3.3.6(b) must be amended so that a market participant is given 10 business days to procure replacement credit support; and

(iv) Clause 3.3.10 must be deleted.

United Energy and Eastern Energy support these conditions of authorisation, while TransGrid opposes all except for condition C8.1(iv).

The applicants have substantial concerns with condition C8.1(iii) of the draft determination which requires the alteration of clause 3.3.6(b). This clause obliges market participants to procure replacement credit support within 24 hours should a market participant's credit support cease to be current or valid. In the draft determination, the Commission stated that this clause placed unreasonable demands on market participants, given that the time to establish replacement credit support is significant. Accordingly, the Commission required amendment of this clause such that a market participant has 10 business days to procure replacement credit support as a condition of authorisation.

At the pre-decision conference, the applicants claimed that this condition significantly changes the risk balance of the market. They argued that clause 3.3.6(b) should be left unchanged, allowing market participants 24 hours for procurement of replacement credit support, as such a situation is likely to occur when the likelihood of default is high, and extending the time allowed results in increased financial impacts.

These arguments were supported in submissions by Loy Yang Power, Pacific Power and Ecogen Energy. In its submission Ecogen Energy argues that it is inconceivable that credit support would have been withdrawn for reasons other than a reduction in the liquidity of the participant. Allowing these participants 10 days to establish replacement credit support places other participants at substantial and unacceptable financial risk.

EnergyAustralia, however, supports the Commission's determination that market participants have 10 days to procure replacement credit support.

Concerning other prudential requirements issues, the incumbent Victorian generators and Hazelwood Power argue that because generators are not able to see the accumulation of credit risk, clause 3.3.10 should be restructured to limit NEMMCO's discretion, rather than deleted as required by the Commission in condition C 8.1(iv) of the draft determination. The applicants' supplementary submission notes that deletion of clause 3.3.10 is unlikely to have a major impact on the overall risk profile of the market.

In its submission the South East Queensland Electricity Board (SEQEB) argues that the sole criteria for determining if a credit supporter is acceptable should be the credit standing of that party. This position is strongly supported by Ergon Energy and the Queensland Treasury Corporation (QTC). Pacific Power argues that clause 3.3.3(a)(1) should be altered to reflect the proposed prudential supervision regulator as outlined in the Government's response to the Wallis Report.

CitiPower is of the view that the prudential requirements in relation to the level of margin calls places unreasonable demands on market participants and may act as a barrier to entry for some new participants and increase costs to end use consumers. The NEMMCO scheme should take into account actual exposure to high spot prices rather than using an average. CitiPower agrees with conditions C8.1(i) and C8.1(iv) of the draft determination.

The EUG questions whether the overall level of prudential requirements are a barrier to entry. SMHEA suggests that accelerating settlements and/or the use of margin calls can be considered as a way of enabling the prudential requirements to be lowered without jeopardising market confidence.

Integral Energy argues that the current prudential requirements are at the appropriate level in view of the market risks of a highly volatile market where spot prices may vary from $0–$5000/MWh.

Commission considerations

The Commission recognises the importance that prudential requirements can play in ensuring market confidence. While parties trading bilaterally in the NEM can assess the credit risk of the counterparty and act accordingly, by adjusting prices or seeking surety, the spot market is a blind market in which sellers are unaware of the identity (and hence financial status) of the buyer.

Prudential requirements can avoid the dual problems of 'free riding' by parties with a high risk of default, and the reduction of the market to a 'lowest common denominator' status where suppliers are forced to impose a general risk premium and customers with good credit standing cannot gain appropriate recognition of their low risk of default. This 'risk premium' attached by generators to trading blindly in the NEM may increase the price at which generators would be prepared to sell.

To minimise this risk premium and standardise the risk of default the Code proposes to raise all buyers to the same level of default. The public benefit from having a common set of prudential requirements for all market participants comes from the smaller risk premium attached to participants in the market, which translates into lower prices.

Whilst acknowledging that some prudential requirements are essential to the smooth operation of the NEM, the Commission is concerned that the package of prudential requirements outlined in the Code may be excessive. The Commission is accordingly of the view that the level of prudential hurdle may impact on entry to the market in which case the benefits of such arrangements may not outweigh the associated anti-competitive detriment. The concerns of the Commission are shared by many within the industry. Virtually all interested parties who discuss prudential requirements in their submissions are of the opinion that the requirements outlined in the Code are excessive. The same views were expressed to the Commission in consultations it conducted with industry participants in April–June 1997.

Aside from the overall level of prudential requirements, there are specific requirements in the Code that raise particular concerns. Clause 3.3.4 states that at the beginning of the NEM the acceptable credit rating will be the highest short term credit rating possible. Further acceptable credit support may only be obtained by market participants from banks or governments.

The Commission notes that while the prudential requirements are flexible in that they will be determined by each market participant's level of trading in the spot market, the inclusion of governments as credit support providers (clause 3.3.3(a)(2)) may have the effect of easing the prudential requirements faced by government owned entities when compared to those of privately owned entities. This is because the governments may choose not to provide credit support at a cost commensurate with the provision of such support in the financial markets, effectively lowering the prudential requirement placed upon government owned entities. This clause, if indeed it does advantage government-owned businesses over privately owned businesses, apart from not being in the spirit of competitive neutrality, may create a barrier to entry for privately owned businesses, thereby increasing the anti-competitive detriment associated with the Code. The Commission imposed a condition of authorisation disallowing governments from acting as credit support providers in its draft determination. The Commission notes that the applicants state that removing the option of governments acting as credit support providers does not significantly alter the risk profile of the market.

Further, the Commission notes the submissions from QTC, SEQEB and Ergon Energy regarding the bias shown in the Code in favour of banks and sees merit in their position that any agency that meets the credit support provider provisions stated in the Code should be considered acceptable. Such a revision would allow all market participants access to a wider range of acceptable credit support providers, decreasing the scope for competitive advantage to accrue to any particular class of market participant. However, this option was not raised at the pre-decision conference and has not been canvassed widely and the Commission considers that such a change to the prudential arrangements should be subject to a full consultation process. Therefore, the Commission recommends that NECA review clause 3.3.3(a) such that all institutions, including but not limited to banks and governments, who meet the acceptable credit rating are able to be eligible credit support providers.

The Commission is of the view that a number of the prudential requirements place considerable demands on market participants. In this regard the Commission notes clause 3.3.4(c), which allows NEMMCO to alter the acceptable credit rating definition on 10 business days notice, and clause 3.3.6(b), which requires replacement credit support within 24 hours in a situation where the credit support provider may have its credit rating downgraded to an unacceptable level. The Commission will, however, permit clause 3.3.6(b), as extending the time allowed to procure replacement credit support would appear to considerably alter the risk profile of the market.

The Commission also notes that some clauses give NEMMCO a great deal of discretion to alter prudential requirements. Such clauses have the potential to be applied in an anti-competitive manner. In this regard the Commission notes the market participant concentration risk levels (clause 3.3.9) and in particular the credit support concentration risk levels (clause 3.3.10). In the extreme, these clauses would appear to give NEMMCO the ability to limit any participant's involvement in the market to any level NEMMCO sees fit. Given the overall level of prudential requirements in the NEM and the potential for clause 3.3.10 to be applied anti-competitively, the Commission requires its deletion as a condition of authorisation. Despite the views of the incumbent Victorian generators and Hazelwood Power, the Commission accepts the applicants' assertion that the deletion of clause 3.3.10 is unlikely to have a major impact on the overall risk profile of the market.

The Commission believes that the conditions of authorisation outlined below largely address the concerns of SMHEA and CitiPower, as the prudential requirements faced by market participants are lowered without having a great impact on the overall risk profile of the market. In relation to Pacific Power's arguments, the Commission considers that as the proposed Australian Prudential Regulation Authority will be concerned with the prudential supervision of deposit taking institutions, life and general insurance companies, and superannuation funds, its relevance to the prudential supervision of market participants in the NEM may be limited. This, however, is an issue that the applicants may wish to consider when the proposals for financial system reform become legislated.

Condition of authorisation

C8.1 (a) Clause 3.3.3(a)(2) must be deleted;

(b) Clause 3.3.4(c) must be amended to provide that the date of effect of a variation in NEMMCO's determination of an acceptable credit rating is not earlier than 30 business days after the date of notification; and

(c) Clause 3.3.10 must be deleted.

8.2 Regions

For the purpose of conducting the spot market the NEM is to be divided into regions. A region is an area determined by NEMMCO and approved by NECA in accordance with clause 3.5, being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both.

NEMMCO, in formulating its recommendation, must consult with market participants in accordance with the Code consultation procedures. NEMMCO must base its decision on set principles which are outlined in clause 3.5.1(b)(2). The Code also includes a process for the revision of boundaries and regional reference nodes (clauses 3.5.2 and 3.5.3).

Issues for the Commission

The Code gives considerable discretion to NEMMCO to determine regional boundaries. The manner of defining these regions has the potential to influence the efficiency of the NEM.

What the interested parties say

The treatment of regions in the NEM was discussed in a number of submissions received by the Commission.

The SMHEA argues that consideration should be given to the amount of firm IRHs participants would be able to buy when defining the boundary of a region. For example, the SMHEA states that it would be able to buy up to a maximum of approximately 700MWs of IRHs to Melbourne if New South Wales were one region, whereas if New South Wales were split into a Canberra–Snowy region and the rest, then it would be able to purchase up to 1100MWs of firm IRHs. The SMHEA claims that the latter option is clearly a more efficient outcome for the market.

The SMHEA adds that the Code needs to specify a process that is beyond political influence, is repeatable and ensures price and dispatch outcomes not materially different from what would have occurred if a purely economic approach had been taken based on the use of actual losses and network configuration rather than pre-determined loss factors and a simplified network model.

The SMHEA states further that it would have concerns if there was just one New South Wales region, as it would be substantially disadvantaged in terms of the volume of IRHs available to it in the Victorian market. The SMHEA adds that a single New South Wales region, combined with clause 3.9.7 which states that generators will not be paid any compensation for being constrained-on, will substantially discriminate against it in the market relative to what would be the case on purely economic outcomes. [44]

The EUG supports the use of clear criteria for determining regions, the use of consultative processes, the involvement of NECA and the publication of information. The EUG argues, however, that until NEMMCO completes this process there will continue to be a lack of information about the specifics of regions within the NEM. The EUG is of the view that this uncertainty poses a potential barrier to long term contracts and discourages new entry. It similarly argues that if the regions in the NEM closely followed existing State markets, the risk of protective measures being used to limit inter-regional competition would be increased thereby negating the benefits of the NEM.

The Victorian DBs argue that the initial regions to apply should be specified now so that there is certainty for market players. They add that if the criteria in clause 3.5.1(b)(2) are applied objectively then Snowy should be a separate region (and not part of a Victorian region or New South Wales region).

Boral Energy expresses concern over how regional reference nodes are to be determined. It argues that the Code does not make explicit how many regional reference nodes there will be or what the price differentials and constraints will be across the regions. This uncertainty, Boral Energy claims, represents a potential barrier to long term contracting and discourages new entry.

TransGrid states that the impact of having new regions or a higher number of regions should not be underestimated, as every new region creates additional requirements for inter-regional hedging. For simplicity, TransGrid claims that it would be best to have the minimum number of regions possible. TransGrid is not yet convinced that there is a requirement for two regions within New South Wales.

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[44] The issue of constrained-on scheduled generating units is discussed in section 9.2.4.

What the applicants say

In their submission the applicants did not specifically discuss the competitive effects of the Code provisions dealing with regions.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation.

C8.2 NECA must, within two years of NEM commencement, conduct and complete a review of the principles for determination of regions as set out in clause 3.5.1(b).

The review must consider the adequacy and appropriateness of these principles, and of any alternative principles that might be added or substituted therefore, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

Delta Electricity, CitiPower, Integral Energy and Macquarie Generation all have concerns that the establishment of additional regions will impact on the risks associated with trading in the financial market. Delta Electricity and Macquarie Generation consider that any change to the definition of regions should only occur where it can be established that benefits sufficient to outweigh the negative impact on the bilateral contracts market will result. CitiPower states that any review should be conducted earlier than two years after market commencement.

SMHEA claims that inappropriate region definitions can impair the efficient functioning of the market, and as yet it is not clear that the present Code provisions will deliver an adequate outcome.

EME argues that regions should be defined along economically efficient lines and is concerned that the issue of historical contracting in New South Wales threatens this outcome.

Integral Energy does not believe that there are valid reasons for the creation of more than one region in New South Wales. In reviewing regions, Integral Energy argues that NECA should be required to consult with non-Code participants, such as those from financial markets, as it is these organisations which will be significantly affected by the review.

The EUG is most concerned that proposals for defining regions in the NEM are being developed by NEMMCO and jurisdictions without proper consultation, including with end use customers.

Commission considerations

The Commission is of the view that the determination of regions has major implications for the public benefit of the NEM arrangements. If the price regions have been configured so that all significant physical network constraints coincide with regional boundaries, efficient pricing outcomes should be produced even when constraints are binding. However, if constraints can arise within regions, regional pricing may then produce inappropriate outcomes. Market participants located on the distant side of an intra-regional constraint from the regional reference node, for example, would experience prices that were higher (for import constraints) or lower (for export constraints) than the economically efficient values.[45] Inefficient pricing outcomes may in turn limit the level of trade in the NEM. Accordingly, the Commission considers it important that generation or load centres separated by network constraints be located in separate regions where possible.

This is an important consideration given that, by providing broad principles for defining the boundaries of regions, clause 3.5.1 of the Code gives considerable discretion to NEMMCO to determine these regions. In this regard the Commission notes, for example, clause 3.5.1(b)(2)(iii) which states that region boundaries should be located so that transfer limits between regions can be clearly defined, and transfer flows across regions easily measured, at the region boundary. It would appear that application of these principles could enable NEMMCO to define New South Wales, for example, either as one region or as a number of regions. In giving considerable discretion to NEMMCO to define boundaries such a clause has the potential to affect the public benefit or anti-competitive detriment of the NEM arrangements. Such clauses can create a degree of uncertainty which may discourage entry into the NEM. The Commission believes that in order for these anti-competitive effects of the Code to be limited the principles for defining regions must be applied consistently and kept beyond political influence. The Commission is also of the view that in performing this role NEMMCO should consider the financial market effects of altering regional boundaries.

The Commission, however, is not in a position to assess the competitive impact of clause 3.5.1 until these principles have been applied and the regional boundaries determined by NEMMCO.

In relation to the arguments of the EUG and Integral Energy, the Commission is of the view that the Code consultation procedures give opportunity for market participants and non-Code participants to contribute to consideration of regional boundaries.

Condition of authorisation

C8.2 The Code must be amended to provide that NECA must, within two years of NEM commencement, conduct and complete a review of the principles for determination of regions as set out in clause 3.5.1(b).

The review must consider the adequacy and appropriateness of these principles, and of any alternative principles that might be added or substituted therefore, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

8.3 Network losses

Electrical energy losses occur when electricity is transported from the point of generation to the point of consumption. In the NEM, loss factors will be applied as price multipliers to the spot price determined at each regional reference node in order to reflect the costs arising from the transportation of electricity.

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[45] Where ‘import’ and ‘export’ are relative to the regional reference node.

The relationship between losses and delivered energy is not linear. Due to the complex and uncertain nature of determining losses the Code makes provision for three types of loss factors:

- inter-regional loss factors are based on marginal losses and will be determined in each dispatch interval in accordance with formulae to be published by NEMMCO (clause 3.6.1);
- intra-regional loss factors are calculated by averaging marginal loss factors over a one year period and are to be determined by NEMMCO (clause 3.6.2); and
- distribution loss factors are based on average losses within the distribution area and are to be approved by the relevant jurisdictional regulator. If, in NEMMCO's opinion, the calculation of a distribution loss factor for a scheduled generating unit would significantly impact on the central dispatch of generation, NEMMCO may require the DNSP to calculate the distribution loss factor in a similar manner to intra-regional loss factors (clause 3.6.3).

The non-linearity of both inter-regional and intra-regional loss relationships results in a settlements residue which is to be allocated according to a methodology to be developed by NEMMCO (clause 3.6.5).

Issue for the Commission

These provisions of the Code may be considered to be:

- price fixing arrangements, to the extent that participants are employing formulae which may have the effect of fixing or controlling the price of electricity in a region; or
- anti-competitive arrangements, to the extent that loss factors which result from the averaging of losses across an area may create cross-subsidies from those whose actual losses are low to those whose actual losses are high, resulting in inequality and inefficient market signals.

What the interested parties say

Macquarie Generation and the Victorian DBs are concerned that the Code's mechanisms with respect to network losses are complex and difficult to understand. The Victorian DBs argue that this level of complexity has the potential to create barriers to entry for new participants and barriers to direct trading for end use customers.

TransGrid, EUG and the ACA note the importance of accounting for losses in order to send the right locational signals. The EUG and Environment Australia express concern that since distributional loss factors are averaged economic signals may be distorted.

The Victorian DBs are also concerned with the 'arbitrary mechanisms' that give rise to the settlements surplus, and the potential distortions that arise from the distribution of this surplus. They state that the aim should be to minimise the settlements surplus that is generated. They suggest that loss algorithms which do not generate any settlements surplus could be easily designed (both for intra and inter-regional losses) thus reducing the bulk of the surplus which is likely to arise under the current Code design.

Boral Energy states that there needs to be clarification of the methodology for the calculation of marginal loss factors for generators embedded in the distribution network.

What the applicants say

The applicants see loss factors as providing economically efficient locational price signals to ensure that:

- the central dispatch process properly takes account of network losses to achieve the most economic outcome for the power system as a whole;
- new investment associated with both electricity generation and consumption reflects the true value of that investment in any location within the market area; and
- the right balance is achieved between investment in generation, demand side measures and/or the main transmission network.

The applicants note that the averaging of losses will only occur in the low voltage distribution network, where it is not economically feasible to develop dynamic marginal loss factors for each distribution connection point. They state that even if it were technically feasible the overall costs of doing so would outweigh any benefits flowing from applying the marginal loss factors to each individual consumer. Thus, they argue there is a public benefit through reduced administration costs and certainty in the arrangements for averaging distribution losses in a region. It is stated that the extent of averaging envisaged in the Code is limited and has no material impact on competitive outcomes in the spot market. Furthermore, it is argued the alternative of measuring losses at every point within a network would be administratively unworkable and prohibitively expensive.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.3 NECA must, prior to 1 January 2000, conduct and complete a review of the financial impact of distributional losses. The review must consider whether marginal loss factors could be used to calculate distribution losses.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report provided to the Commission.

This issue was not raised at the pre-decision conference but has been addressed in subsequent submissions from CitiPower, SEQEB and the incumbent New South Wales DNSPs. Each of these submissions was against using marginal loss factors to calculate distribution losses, stating such a process would be complex, costly and have very little benefit to end users. The incumbent New South Wales DNSPs stated that in the current New South Wales market the true-up loss adjustment is a very small proportion of total losses, rendering the use of marginal loss factors redundant.

EnergyAustralia submits that there is little benefit in any review by NECA extending to the application of marginal losses within distribution networks.

SEQEB added that network losses contribute significantly (5-10 per cent) to greenhouse gas emissions in Australia, and any review of losses would better consider how the NEM could signal NSPs to invest in loss reducing technology, rather than review marginal distribution losses.

Eastern Energy stated that any review would need to take into consideration the rural/urban cross subsidy inherent in the current loss factor calculation.

Commission considerations

Consideration of losses in the spot market, as noted by the applicants, is necessary in order to provide economically efficient locational price signals to ensure that central dispatch and pricing achieve the most economic outcome. Consideration of losses is also important in ensuring that new investment is appropriate and that the right balance is achieved between investment in generation, demand side measures and/or the main transmission network.

This implies that if two or more generators at different locations are offering to supply the spot market at the same price, preference should normally be given to the one which would result in the least additional transport losses, unless transport constraints dictate the outcome. In general, this will result in preference being given to generators that are situated close to load. Thus the dispatch and spot price determination processes, which take into account network losses, will impact on the location of generation and load on the grid.

A methodology to recover the cost of losses from market participants in a fair and reasonable manner is therefore essential. There are two methods by which losses can be accounted for: volume adjustments or price adjustments. The Code has focused on a price adjustment to reflect the incremental cost of each additional MW of electricity transmitted, because it overcomes the shortcomings of volume adjustments.

NEM design

In the long interconnected market covering New South Wales, Victoria and South Australia there is potential for the marginal cost of losses to represent 20–25 per cent of the marginal cost of energy. However, average losses may be only three per cent of total sales.[46] Given the significant difference between marginal and average losses, economically efficient pricing will only occur if marginal losses are taken into account. In the NEM, loss factors are applied to the spot price determined at each regional reference node. This means that electricity generated further from load is more expensive because it incurs a higher loss factor than electricity located close to load.

For marginal system losses to be included in market pricing there is a need to predict losses. Losses are very unpredictable as they can vary with the season and time of day. Depending on the system's physical characteristics and operating circumstances an increase in delivered energy can cause either a positive or negative change in losses at the margin. The methodology for determining losses is currently not fully developed. At best it is only possible to estimate marginal system losses. To use a fully dynamic marginal approach for the entire network may be too complicated and could act as a barrier to entry for market customers and, indirectly deliver economically inefficient outcomes. This is a concern put forward in the submission from the Victorian DBs.

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[46] Market Trading Working Group Position Paper No. 14.

The current Code design tempers a full marginal loss approach in the interests of simplicity by replacing it with one in which dynamic marginal loss factors apply for the transfer of electricity inter-regionally, static marginal loss factors apply intra-regionally and loss factors based on average losses apply over a distribution area.

Inter-regional and intra-regional losses

Inter-regional trade will be determined on the basis of dynamic marginal loss factors. Equations describing inter-regional loss factors between each pair of adjacent regional reference nodes in terms of significant variables will be derived by NEMMCO performing an analysis on load, generation and network data for each trading interval in the previous financial year. The Code requires NEMMCO to review the equations used to calculate inter-regional loss factors in each financial year and publish the equations by 1 April, prior to the financial year in which they are to apply (Schedule 3.2).

For simplicity, intra-regional losses will be represented in the spot market though static marginal loss factors calculated annually by analysing a representative range of network flow patterns. Static loss factors can provide price signals which are correct on average over the year. However, there might well be many occasions during the year when these signals are inconsistent with actual power flows. Therefore, annually calculated static loss factors provide medium to long term price signals rather than accurate short term signals.

Due to the fact that static marginal loss factors will on average exceed actual losses, settlement on the basis of static marginal loss payments will exceed those required to cover actual losses, and this gives rise to a settlements residue. According to the Code the settlements residue will be distributed back to participants according to clause 3.6.5. The allocation of the settlements residue has economic implications depending on how and to whom it is distributed.[47]

The Victorian DBs submit that the aim should be to minimise the settlements surplus generated. The current approach in New South Wales under the NEM1 Stage 1 reflects this view. In New South Wales the settlements residue accumulated in each half hour trading interval is distributed back to pool participants in proportion to the amount of electricity consumed in that trading interval. This approach results in a loss of efficiency benefits, as the resultant effective price of electricity does not preserve the marginal loss based component.

Thus the averaging of losses over the network gives rise to price distortions and will eliminate an important locational signal. Therefore there is merit in using the marginal loss based approach in the transmission network, even though it may entail some complexity.

The Commission does acknowledge that simplifications and approximations will occur, and that the financial impact of these approximations is largely unknown at present. However, the Commission concurs with the sentiment expressed by TransGrid in its submission that the calculation of loss factors, as proposed in the Code, attempts to reflect physical reality in a pragmatic way. These calculations are clearly only an approximation but they do reduce uncertainty and send a meaningful locational signal. The yearly review will also ensure that loss factors are kept up to date.

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[47] These issues are discussed in section 8.9.

The Commission also supports the suggestion by SEQEB that a review of losses could beneficially consider how the NEM arrangements signal efficient investment in technology designed to reduce losses on the network.

Distribution losses

Distribution pricing has been simplified as it entails average losses. It is accepted and acknowledged by the applicants that the averaging of losses will entail some degree of cross subsidisation. However, average losses will only apply to the low voltage distribution network where it is said to be not economically feasible to develop dynamic marginal loss factors for each distribution connection point. The applicants state that even if it was technically feasible to consider marginal losses in the distribution network, the overall costs of doing so would outweigh any benefits flowing from applying the marginal loss factors to each individual consumer.

The difficulty and complexity of developing a marginal approach to distribution losses may be such that an average approach is justified in the early stages of the market. The Commission notes the submissions received that suggested that application of marginal loss factors to the distribution networks is too complex and costly compared to the benefits received. However, as the NEM develops this current state of affairs may alter and the Commission is of the view that the efficiency benefits of a marginal approach must be investigated.

Condition of authorisation

C8.3 The Code must be amended to provide that NECA must, prior to 1 January 2000, conduct and complete a review of the financial impact of distribution losses. The review must consider whether marginal loss factors could be used to calculate distribution losses.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

8.4 Spot price determination

Clause 3.9 of the Code sets out the manner in which spot prices are to be determined. The principles applying to the determination of prices for electricity transacted in the spot market are set out in clause 3.9.1, while procedures for determining spot prices are set out in clause 3.9.2.

The basic principle of spot price determination is that the price at each regional reference node should reflect the marginal value of supply at that location and time, this being the price of meeting an incremental change in load taking into account all relevant constraints and transport losses (clause 3.9.2(d)).

A ‘dispatch price’ at each regional reference node is to be calculated every five minutes in accordance with the above principle.[48] The spot price at a regional reference node (the ‘regional reference price’) for a particular half hour is set equal to the average of the dispatch

[48] The dispatch price is defined as the price determined for each regional reference node by the dispatch algorithm each time it is run by NEMMCO.

prices applying through that interval. Finally, the spot prices to apply to electricity traded at individual connection points are obtained by adjusting the regional reference price for transport losses.[49]

Issues for the Commission

As the NEM arrangements require all electricity to be transacted through the spot market and at the spot price these provisions may be considered to be:

- exclusionary provisions, to the extent that competing participants agree not to trade with other persons except through the spot market;
- exclusive dealing provisions, to the extent that market participants agree to trade on condition that they will not supply electricity to, or acquire electricity from, unregistered persons;
- price fixing provisions, to the extent that participants are agreeing that a particular pricing mechanism will be used to determine prices; or
- provisions having the purpose or effect of substantially lessening competition, to the extent that a requirement to trade through the spot market or to trade at particular prices creates barriers to entry to, or lessens competition in, the electricity market.

What the interested parties say

Ecogen Energy has major concerns with the price setting mechanism set out in the Code. It argues that because prices are set through the averaging of six five–minute prices for the half hour, the marginal generator is not guaranteed to get paid its offer price. Ecogen Energy states that it is unacceptable for units to be dispatched and be paid less than the offered price.

Macquarie Generation acknowledges that by setting the price each five minutes and then averaging over the half hour to produce a trading interval price, the spot price will be dampened. However, it argues that clearing the market every five minutes is not a practical alternative due to the sheer volume of data that will be produced. It also questions whether this is technically possible with current metering. Macquarie Generation states that the options, therefore, are to set the half hour price at either the highest five minute price, the lowest five minute price, or the average. The average, it claims, is clearly a reasonable compromise.

What the applicants say

The applicants argue that a competitive spot market with a common clearing price is the simplest and most efficient means of balancing supply and demand for electricity at any point in time. An electricity spot market can work much like any other wholesale market in which buyers and sellers make offers, determine the prices at which supply equals demand, and trade the product at those prices. Some special market arrangements are needed to deal with the unique characteristics of electricity, but these arrangements are different only in degree from those functioning in other commodity markets.

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49 There are a number of circumstances in which the spot price is not determined according to these principles. These are outlined in clauses 3.9.3 to 3.9.7. This determination discusses three such provisions — price cap (section 8.6), price floor (section 8.7) and pricing for constrained-on scheduled generating units (section 9.2.4).

Thus the applicants argue that because of the unique characteristics of electricity as a product, a spot market is a necessary facilitator of competitive trading in electricity. This facilitation role does not lessen the competition that will occur in the NEM. Indeed, the NEM increases the degree of competition by enabling a greater level of inter-jurisdictional trade.

The applicants submit that the mechanisms to establish spot prices mimic those in traditional markets (the interplay of supply and demand). It is further argued that central co-ordination is an essential element required by the need to balance supply and demand on an instant by instant basis. As such, NEM pricing mechanisms, and the mandatory participation in the spot market, produce a competitive outcome. The applicants conclude that the public benefits of market efficiency and equitable treatment of participants delivered through this mechanism far outweigh any perceived detriment arising from any lessening of competition.

Issues arising from the draft determination

At the pre-decision conference and in a subsequent submission, Southern Hydro stated that the primary problem with the current pricing mechanism is that generators can be called for short periods of time and not be paid their offer price. This has happened to Southern Hydro on numerous occasions and, in its view, amounts to a provision of an ancillary service without any remuneration.

Southern Hydro considers that the current pricing mechanism is inadequate because it does not send the correct market signals but it recognises that any changes need to be fully considered and the appropriate systems developed. Therefore, it recommends that NECA review the pricing mechanism, through industry consultation, after six months of market operation.

Commission considerations

Five minute dispatch pricing was raised by some generators during the Commission's NEM1 Stage 1 consultations as a major issue. However, it appears to have become less of a concern since the commencement of NEM1.

Some generators argue that a fundamental principle of market design should be that a generator receives its offer price whenever it is dispatched (also refer to section 9.2.4 which deals with pricing for constrained-on scheduled generating units). With the spot price for each half hour calculated as the time weighted average of the six five–minute dispatch prices, this will not be the case when a generator is dispatched for only some part of a half hour trading interval. Consequently, it is claimed that generators face financial risk.

It is also claimed that five minute pricing suppresses price volatility in the market. As a solution, some generators have argued that the highest priced generation dispatched in a trading interval should set the spot price.

The Commission, however, considers that demand side bidders face a similar problem. Customers could similarly argue that the price they have to pay should be no more than their bid price for each five minute period. Under the current proposed approach they may have to pay more than their bid if they were to consume for part of a half hour trading interval only. Some market customers therefore have proposed that the lowest priced load dispatched in a trading interval should set the spot price.

Due to this dilemma of whether the spot price should be set by the maximum or the minimum dispatch price, the average has been suggested as a compromise.

The consequences of adopting an alternative to the time weighted approach needs to be considered in terms of:

- possible loss of market efficiency; and
- whether it unduly favours some participants and/or discriminates against others.

In this respect, a broad number of alternative approaches have been proposed and are canvassed in a paper by Victorian Power Exchange (VPX).[50] VPX has undertaken some comparative modelling of market price outcomes under a number of these different possible algorithms for determining spot prices. The results suggest that the possible market distortion arising from the simplified time weighted approach is insignificant and therefore does not justify the adoption of any of the alternative approaches and the additional problems accompanying them.

In addition, the practical difficulties of moving to an alternative system at this stage have been highlighted to the Commission. The issue primarily arises because the dispatch interval (five minutes) is not aligned with the settlements period (half hour). The Commission has been advised that to move to five minute settlement and pricing would require significant additional IT resources, particularly for settlement. Moreover, current metering, which meets international standards, is not sophisticated enough to handle any finer detail than half hour pricing.

Indeed the Market Trading Working Group concluded that the time weighted approach had the advantages of:[51]

- simplicity and transparency;
- being as close as practicable to a real time price setting approach;
- apparently being an even-handed treatment of both supply side and demand side bidders; and
- avoiding any form of compensation via uplift payments.

The Commission supports these findings and is therefore of the view that the public benefits of the current proposed mechanisms to establish spot prices in the NEM would appear to outweigh any identified inefficiencies. Moreover, the Commission is not convinced that generators will be exposed to undue risk as forecast sensitivity data provides a price revelation mechanism and hedging options are available.

The Commission acknowledges that five minute pricing particularly concerns high cost fast start generators, which can operate for a few hours only in a given year and therefore must

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50 VPX, *Draft for Discussion, 5–Minute Pricing Issues and Options Paper*, Pool Consultative Committee 96–47–15. This report canvasses five approaches to spot price determination: the current design, half hour ex ante spot price determination, optional 5–minute trading interval in conjunction with a market levy, 15 minute trading interval, and compensation in conjunction with an uplift payment.

51 Market Trading Working Group, Position Paper No. 15, *Price Pool Calculation*, November 1994.

recover all their costs in a short period. It is recognised that five minute pricing entails some dampening of price volatility. The Commission is of the view, however, that generators will factor into their bidding behaviour the knowledge that prices will be averaged.

The Commission also considers that features of the NEM, such as market structure issues, the number of participants and the degree of contestability, will affect the efficiency of spot market outcomes. Procedures such as bidding arrangements and information disclosure provisions will impact upon the competitiveness of these spot market outcomes. These issues are raised in more detail in sections 8.5 and 8.11.

In summary the Commission is of the view that the current time weighted pricing approach be maintained. It is felt that it is a simple and transparent method of spot price determination and the possible market distortions arising from adopting this approach would appear to be minor.

8.5 Rebidding

Participants in the wholesale market submit available generating capacity and scheduled loads as inputs into the make up of the short term projected assessment of system adequacy (PASA). Changes to total capacity and the MW quantity specified for each price band are subject to the rebidding conditions set out in clause 3.8.22. The price specified for each price band in the dispatch bids and offers (except for offloading prices) can not be changed after they are submitted.

Issues for the Commission

The Commission must assess whether the efficiency benefits of allowing rebidding outweigh the potential for this feature of the market design to be used to manipulate spot market price outcomes. While such behaviour may not contravene the TPA, it could significantly detract from the potential public benefits of the market arrangements.

What the interested parties say

In submissions and consultations most generators, such as Delta Electricity and Macquarie Generation, are of the view that rebidding is essential for efficient operation of the supply side of the market and that limiting rebidding, for example to bona fide technical or physical reasons, is unworkable.

Macquarie Generation states that it is concerned with the Commission's recommendations for NEM1 Stage 1 in regard to the adoption of the VicPool approach. It contends this approach would allow the market operator to either accept or deny a rebid judged on circumstances that could have been foreseen. Macquarie Generation feels that this approach will not give consistent answers, and as such will impact upon each participant differently.

Market customers, such as energyAustralia and the Victorian DBs are concerned with the ability of generators to use rebidding to game the market, particularly in the present circumstances, due to the immaturity of the demand side. EnergyAustralia argues that rebidding right up until the time of dispatch creates an opportunity for generators to manipulate the pool price in a time frame within which the customer side of the market cannot respond.

EnergyAustralia considers that rebidding with shorter notice would appear to raise the additional concern of system security and the potential for system instability. EnergyAustralia argues that a cut-off time needs to be employed such that a rebid will not take effect until at least the next trading interval or half hour (whichever is greater).

EnergyAustralia and the Victorian DBs recommend that rebidding should only be permitted when generators can demonstrate a bona fide technical or physical reason for altering a bid and not merely an economic reason for the change.

Integral Energy contends that rebidding has the potential to destabilise the market and send incorrect pricing signals to customers.

Ecogen Energy states clause 3.8.22(a) provides that changes to available capacity after the submission time has closed are subject to the conditions set out in clause 3.8.22, but it says these conditions are not set out. Ecogen Energy notes that clause 3.8.22(c) provides for changes in MW quantities of the price bands but does not provide for changes in availability or commitment. It is of the view that changes in availability, self dispatch level and commitment status should be 'locked in', and clause 3.8.22 should cover such changes, as per the current clause 3.8.22(c). These changes will relate to substantial changes of generation availability, and it is important for the market to know why, say, a 500MW unit previously committed is decommitted with one hour's notice, causing a significant increase in prices.

What the applicants say

The applicants make no comment about the rebidding provisions in their submission.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.4 Clause 3.8.22 must be revised to prohibit all rebidding of MW quantities within three trading intervals prior to dispatch.

At the pre-decision conference and in subsequent submissions market customers generally supported the restriction on rebidding, and market suppliers and the applicants opposed the rebidding restriction.

Support for rebidding restrictions

Those in favour of restricting rebidding argue that as the time prior to dispatch decreases the market power of generators increases, and the opportunities for generators to use this power for their commercial advantage also increases. Allowing rebidding up until the time of dispatch imposes a cost on market customers, where generators rebid quantities into higher price bands within a timeframe such that customers are unable to respond to the price changes. CitiPower comments that the three trading interval restriction seems a reasonable balance between allowing generators to respond to market signals and manipulate spot prices.

United Energy argues that 90 minutes may not be sufficient restriction on rebidding and suggests that the original suggestion by the Victorian DBs to totally restrict rebidding except for capacity changes for bona fide technical reasons would be more appropriate. Powercor supports that position suggesting a 24 hour restriction on rebidding, except for bona fide technical reasons.

BCA/EWG stated that end users have limited ability and limited opportunity to join the market, and the demand side of the market has a comparatively insignificant ability to impact on prices relative to the supply side. The BCA/EWG support the rebidding restrictions as an attempt to control generators arbitrary removal of capacity to force prices higher.

The BCA/EWG and energyAustralia also supported a compromise position, under which rebidding up until the time of dispatch would be allowed if it resulted in lower spot prices, but disallowed if it resulted in higher spot prices. The BCA/EWG submission included changes to total capacity as well as changes to MW quantities in each price band in its discussion of rebidding.

This compromise position was supported by Delta Electricity, but only as a second best outcome, their primary position was that there be no restrictions on rebidding in the market.

Support for <u>*no*</u> *rebidding restrictions*

Those supporting no restrictions on rebidding generally argue that in order for generators to respond to changing market conditions rebidding must be allowed. There was particular concern regarding any attempt to restrict rebids of total capacity, which, must be allowed in order for generators to notify the market and system operator of unexpected outages.

The applicants state that rebidding gives market participants scope to respond to changing conditions rapidly, in a manner that is in their best commercial interests. The applicants also state that rebidding would generally be expected to occur in response to an outage, and the generator suffering the outage would rebid remaining capacity into lower price bands to ensure their contract position is covered, thus depressing the spot price. The incumbent Victorian generators agree, stating that generators cannot be stopped from taking a unit out (for example if there is a forced outage), therefore the price may increase if rebidding is not allowed. By not allowing the market to respond to an outage, the incumbent generators (New South Wales, South Australian and Victorian) state that the spot price will be higher than it otherwise would be if rebidding is allowed.

Southern Hydro gave the example that gas powered generators would be likely to be buying gas in a spot market and therefore needed to be able to respond quickly in the electricity market to changes in the price of their input (gas). SMHEA presented a case for allowing rebidding, whereby it allows the managers of hydro plant to ensure their limited energy suppliers are sold at the most beneficial time (ie at peak demand) and in doing so keep peak demand spot prices lower than they otherwise may have been.

Further, the rebidding restriction may not actually achieve the desired result, in that generators can still withdraw capacity (through the rebidding process) which would increase prices, and with the restriction in place other generators could not respond, resulting in higher than otherwise spot prices. Hazelwood Power notes that the rebidding restriction is unlikely to prevent manipulation of spot prices, by those with the market power and desire to behave in such a manner.

The applicants note that if withdrawal of capacity does take place, this may have a greater detrimental effect than the shifting of capacity into higher price bands, as it may have system security implications and result in intervention by NEMMCO.

Pacific Power states that there would be large compliance costs associated with the imposition of a rebidding restriction.

Regulatory response

The Institute of Public Affairs states that the restriction on rebidding was an inappropriate response to try and control possible gaming or anti-competitive behaviour in the market. Pacific Power also supported this view, stating that inappropriate behaviour by generators should be addressed through NECA and Code compliance arrangements, or other appropriate regulation.

Dr Hugh Outhred states that the restriction on rebidding should be removed and alternatives to controlling short term gaming problems be explored. Other participants raise the issue of market monitoring or other regulation to be used as a tool for controlling behaviour in the market. In particular, they state that regulatory measures would be less costly, and cause less distortion to the market outcomes while achieving a better result.

Concerns regarding the options for controlling rebidding behaviour that has an anti-competitive impact on market outcomes were also discussed at the pre-decision conference. Some participants indicated that they considered the TPA an adequate tool for controlling the **use** of market power, however, the Deputy Chairman of Commission clarified that the TPA prohibits the **misuse of market power**, and rebidding to maximise commercial advantage may not contravene the TPA.

Technical feasibility

The applicants also raise the issue of the technical limitations of the market systems and the impact that limiting rebidding will have on generators ability to operate effectively and manage risk in the market. The market design does not make allowance for the fact that some plant is not continuously variable in loading, and must be either fully on or fully off. The linear programming dispatch process developed by NEMMCO can not accommodate such inflexibilities and participants were expected to manage these so called 'quantisation' problems through the rebidding process.

The incumbent (New South Wales, South Australian and Victorian) generators also note this issue in their submissions.

Other factors

The generators have also stated that the 90 minutes restriction, adapted from the current arrangements in NEM1, is arbitrary and inappropriate, as it was imposed in the NEM1 because of system operation concerns, not concerns regarding market behaviour.

Ecogen Energy stated that if there is a restriction on rebidding and something goes wrong, the generator can not get back into the market for 90 minutes unless directed by NEMMCO. If the restriction on rebidding remains then the intervention process needs to be re-examined to ensure that there is equitable treatment.

EME also argues that the restriction does not recognise the risks taken by generators in the market and it does not encourage demand side responses to be developed. There are enough solutions and facilities for the demand side to respond, therefore there is no need for the rebidding restriction.

A further consideration raised by the incumbent generators is the fact that rebidding restrictions would also apply to dispatch offers (demand side bids) and restricting the flexibility of the demand side response may discourage flexible load from entering the market. This may have a cost both in terms of less responsive demand, and less efficient provision of ancillary services. They contend that owners of flexible load that could provide ancillary services will be less likely to offer such services into the market, if rebidding restrictions apply.

Commission considerations

The Commission accepts that the dynamic nature of the supply of electricity means there has to be flexibility in the bidding process to cover the contingency that plant may become unavailable, or extra plant may be unexpectedly required.

Cost to the market of allowing rebidding

The rebidding provisions may give rise to anti-competitive market outcomes through the behaviour of generators. Rebidding up until the time of dispatch creates a situation whereby generators are able to manipulate pool prices in a time frame within which market customers and some other generators cannot respond.

It would appear to the Commission that the use of rebidding for anti-competitive behaviour is most likely to be last minute shifting of MW quantities to higher price bands or withdrawal of capacity from the market. Given the current inflexibility of demand either of these rebidding strategies can have the effect of forcing on higher priced quick response generation, thereby forcing an overall higher price. The Commission is aware that in the New South Wales market generators have withdrawn capacity because of low pool prices, despite the fact the pool price exceeded the price submitted by the generator in its initial bid. However, this behaviour occurred under a different, although similar, set of market rules, and it is not clear that such behaviour in the New South Wales market is indicative of likely outcomes in the NEM.

The effect and likelihood of generators using these rebidding strategies is tempered by the degree of spot market exposure of both spot market customers and suppliers. Currently most participants have a high degree of contract cover and only limited spot market exposure. This situation lessens the financial hardship that will occur if rebidding strategies to force the spot price higher are successfully implemented.

Similarly, the benefit to generators of such strategies is limited by the extent of their spot market exposure. This in particular will limit the usefulness of withdrawal of capacity as a strategy to force spot prices higher, as the generator engaging in such conduct has to drive the price sufficiently high to make revenue earned for less production (and higher price) greater than the revenue that could have been earned with the higher production (and lower price). A rational generator will also have to have sufficient capacity to still meet their contractual obligations after withdrawing capacity to force the price higher.

However, it is the case that the spot price will influence contract prices, and the greater the volatility and level of the spot market the higher the strike price for contracts can be expected to go. The Commission also is aware that the current levels of contract cover, in part due to vesting arrangements may not be reflective of future market arrangements.

Cost to the market of not allowing rebidding

The Commission accepts that there is a cost to the market of not allowing rebidding up until the time of dispatch. The applicants have stated that rebidding should generally depress prices, and restricting rebidding will result in higher than otherwise spot prices. The

Commission accepts that this is the case, particularly where portfolio generators wish to rebid MW quantities into lower price bands, to ensure dispatch up to their contracted capacity, in response to a unit failure.

Further costs of restricting rebidding occur where hydro and gas fired plant cannot rebid to optimise their energy production, in response to changing market conditions. Such rebidding would be to ensure that their output is produced to satisfy peak demand, and would therefore have the highest value to the market. Gas fired plant may also want to rebid in very short time frames in response to changing gas market conditions.

The Commission considers that such costs are not inconsequential, although the impact of the overall higher than otherwise prices would again depend upon the contract positions of the market participants.

There will also be costs associated with some generators having to develop and apply risk management strategies associated with conforming to dispatch instructions that do not take into account their plant inflexibilities.

The Commission also notes that such rebidding restrictions may have the perverse effect of discouraging demand side entry to the market. The Commission is aware that there is currently only limited scheduled demand offered into the market. Rebidding restrictions will also apply to scheduled demand offers (load which is subject to dispatch), and may make participation in the market less attractive. This could impose further costs to the market, as scheduled load can compete with generation to provide some ancillary services, over and above increasing demand side responsiveness.

Commission options

Disallow rebidding of MW quantities into different price bands within three trading periods prior to dispatch

This option reflects the condition of authorisation imposed by the Commission in its draft determination.

From the information provided, at the pre-decision conference and in subsequent submissions, the Commission now considers that this restriction imposes significant costs upon market participants. These costs are in the form of higher spot prices (in some instances), inefficient production outcomes, increased risk management costs to some generators and possible costs arising from discouraging demand side participation in the market.

The Commission has also noted the contention of the generators, and some market customers that such a restriction is unlikely to be effective. Not only have the generators signalled that alternative rebidding and bidding strategies could be used to manipulate spot prices, but market customers have stated that they consider the three trading period restriction ineffective. In the latter case, market customers were calling for an increased time for restrictions to rebidding — of up to 24 hours.

The Commission considers that the complete restriction on rebidding of MW quantities with in three trading periods is unlikely to be effective in curtailing the costs of strategic rebidding behaviour of generators, and will impose significant costs on market participants.

The Commission notes Powercor's call for increasing the period in which the restriction will apply to 24 hours, but considers that while such an arrangement may allow for greater demand side responsiveness, it is likely to increase the costs to the market arising from inefficient production outcomes, risk management and higher spot prices at times of unexpected plant outages.

The Commission does not consider that the rebidding restriction should be extended to all rebidding, ie to total capacity or plant inflexibilities, as such arrangements would be costly to the market in terms of compliance with dispatch. The dispatch process requires accurate information and where a unit trips out of service it is essential that NEMMCO is notified as soon as possible. This process of notification is undertaken through the rebidding process. Similarly, in response to such outages, rebidding of capacity into the market can prevent interventions, and allow the continual functioning of the market without distortions.

Allow rebidding that has the effect of depressing spot prices

A compromise arrangement, suggested by Delta Electricity at the pre-decision conference, was that rebids into lower price bands should be allowed up until the time of dispatch, and the rebidding restriction (of three trading intervals) would only apply to rebids that shifted MW quantities into higher price bands. The Commission notes that this compromise received some support from market customers. This restriction would eliminate the generators ability to manipulate spot price outcomes through rebidding of MW quantities, as any such rebids would have the effect of reducing — or not increasing — the spot price.

The Commission acknowledges the benefits of this compromise arrangement as it would allow generators to rebid in response to unit outages, as they claim they will wish to do, to meet contractual obligations. Thus the cost to the market of not allowing rebidding will be reduced.

This compromise arrangement would also provide generators an option for dealing with the dispatch inflexibilities arising from the dispatch model. Under this arrangement there will still be some additional risk management costs but they will be less than the costs under the no rebidding option.

However, the Commission has concerns regarding this proposal.

This proposal does not address the issue of rebidding total capacity, where such rebids could be used to manipulate spot price outcomes.

Further this proposal may also impact upon other legitimate rebids, in the sense that they will be disallowed. Such cases included rebidding of hydro or gas fired plant in response to changing market conditions, so that the electricity produced is utilised at times of peak demand. In that instance a rebid into a higher price band is valid in the sense that it is beneficial to the market overall and is not undertaken for the purpose of manipulating spot prices in the short term. The compromise arrangement proposed has the effect of introducing inequity into the treatment of generators, based on their technical characteristics.

This compromise rebidding arrangement will also not address the impact of rebidding restrictions on demand side entry to the market, and the possibly perverse signals sent by this restriction.

Allow all rebidding for bona fide technical reasons

This option reflects the current Code arrangements, but imposes an additional criterion that rebids must only be for bona fide technical reasons — ie changes to plant availability.

The benefit of such an option is that it would restrict the ability of generators to rebid for commercial reasons. Not allowing generators to withdraw capacity for economic reasons should encourage genuine original price/quantity bids, therefore providing for a more accurately informed market. The release of information regarding the rebid would be in the public domain and generators who were not complying would be subject to public scrutiny.

The Commission has reservations about the effectiveness of such arrangements. In the draft determination a similar option was rejected on the grounds that substantiation of rebidding 'bona fides' may not be practicable, as technical justifications for rebids could easily be manufactured in response to commercial incentives.

The definition of what may constitute a valid rebid for technical reasons is well outside the scope of the Commission, but crucial to the effectiveness of this option. This option would also address the issue of the technical feasibility, and risk management requirements arising from the dispatch algorithm, assuming that rebids to manage the quantisation problems were given the status of a valid technical rebid. Similarly, it may reduce the barrier to entry that restricting rebidding would form for demand side participants, again depending upon what is accepted as a bona fide reason for a rebid.

This option does not take into account the fact that there are valid non-technical reasons for rebidding, and that such rebidding may be beneficial to the market.

Allow all rebidding — with market monitoring

This option accepts the Code arrangements as they stand but imposes an obligation for the market to be monitored and that monitoring to assess the impact of rebidding on market outcomes.

The option addresses the concerns raised regarding the costs to the market of restricting rebidding. With no restriction in place all market participants are able to rebid MW quantities into higher or lower price bands, up until the time of dispatch. The Code currently provides for rebids to be submitted with reasons, and places an obligation on market participants to be able to substantiate the reasons for their rebids if called on to do so. This information is available upon request to all market participants.

This option has a downside risk of rebidding behaviour being used to drive spot market prices higher, for either short or long term benefit to market suppliers. The extent of this risk will depend upon spot market exposure of generators, the relationship between spot prices (both level and volatility) and contract prices, the spot market exposure of market customers, and the degree of demand side flexibility.

Commission decision

As signalled at the pre-decision conference, rebidding behaviour designed to manipulate spot market outcomes is not *prima facie* in contravention of the TPA. The Commission's concerns relate to the fact that this behaviour will detract from the public benefits arising from the operation of the NEM.

The Commission considered the benefits and costs associated with restricting rebidding, in some manner, against the benefits and costs of allowing rebidding, as currently provided for in the Code.

The Commission's concerns with imposing restrictions include introducing distortions to the market, imposing costs on the market, introducing inequities in the treatment of generating plant, and introducing perverse incentives regarding demand side participation. Further the Commission accepts the generators' and applicants' statements that restrictions on rebidding will be ineffective to the extent that market power and the will to manipulate price outcomes exist. The Commission also considers that the benefits of strategic rebidding by generators will also be limited by the extent of their exposure to the spot price.

For similar reasons the Commission also has concerns regarding both the actual impact of strategic rebidding behaviour on market customers. Currently exposure to the spot price is limited, and although this may not always be the case (either for given participants or generally into the future), the Commission considers that at market commencement it offsets the risks of high spot prices to some extent.

Therefore the Commission has decided to remove the condition imposed in the draft determination, and allow the rebidding provisions of the Code to stand. However, the Commission will impose a condition of authorisation regarding market monitoring, extending the role envisioned under condition C8.12 of the draft determination. That is, the market monitoring function that is to be introduced will be extended to specifically require an assessment of the impact of rebidding on spot market price outcomes.

This position is consistent with the Commission's stance on market information, which is analogous to rebidding, as both are needed for the effective operation of the market, but both have a downside risk of facilitating anti-competitive behaviour.

The market monitoring function is crucial to assessment of market behaviour, both with respect to possible contraventions of the TPA and anti-competitive outcomes that detract from the public benefits of the market. Consideration of the information accumulated by market monitoring will drive possible market reforms into the future, and where anti-competitive behaviour is apparent the Commission will act to get the market design or arrangements altered to prohibit such behaviour.

In relation to the concern raised by Ecogen Energy over changes to available capacity, it is noted that commitment and decommitment decisions are covered in the Code and require participants to notify NEMMCO of any changes and, if required, comply with NEMMCO direction (clauses 3.8.17, 3.8.18, 4.9.6 and 4.9.7). In any event, clause 4.9.9 states that a scheduled generator must, without delay, notify NEMMCO of any event which has changed or is likely to change the operational availability of any of its scheduled generating units, whether the relevant generating unit is synchronised or not, as soon as the scheduled generator becomes aware of the event.

Condition of authorisation

C8.4 The Code must be amended to provide that:

(a) NECA must monitor any significant price variation between the spot prices in any given trading period and the prices forecast and published by NEMMCO for that trading period;

(b) NECA must, in consultation with the Commission, determine guidelines as to what constitutes a significant price variation referred to in (a) above;

(c) NECA must prepare and issue a report every three months, or more frequently if required by the Commission. The report must:

(i) be issued no later than four weeks after the end of each three month period;

(ii) identify and review each significant price variation that has occurred since the previous report;

(iii) provide an opinion as to the reasons and/or causes of each significant price variation;

(iv) be available to members of the public on request; and

(v) be provided to the Commission.

(d) if the Commission requests NECA to provide a report to the Commission on specific market outcomes identified by the Commission, NECA must provide the report to the Commission as soon as possible but no later than four weeks after the request is made, and must include in the report an opinion on the reasons and/or causes for the market outcomes.

8.6 Price cap

The value of lost load (VoLL) is a cap on regional reference prices. VoLL will apply in situations where there is insufficient supply to meet demand and involuntary load shedding occurs. In such a situation all generators able to produce electricity to help meet demand will receive the price cap for their output rather than the true market value.

Clause 3.9.4(b), which sets VoLL at $5000/MWh, is a protected provision. The Reliability Panel is to conduct a review of the value of VoLL, in consultation with market participants, within twelve months of market commencement (clause 3.9.4(c)). Any recommended change to the value of VoLL as an outcome of this study will be dealt with as a recommended change to the Code (clause 3.9.4(c)). However, any change will not take effect less than two years after the date of the notice of the change being published (clause 3.9.4(d)).

Issues for the Commission

The price cap may constitute a form of price fixing under s. 45 of the TPA. The Commission must compare the potential anti-competitive detriment arising from the imposition of a price cap to the benefits of avoiding price spikes which might occur before both customers and generators have had the opportunity to fully establish response mechanisms.

What the interested parties say

The majority of parties who made submissions to the Commission support VoLL, especially in the initial stages of the NEM.

The Victorian DBs reject any possible argument that the concept of VoLL is inappropriate in a market based system. They believe that:

- VoLL should be set at a very high level;
- the electricity market is one where customers in real time do not have the ability to reduce load in response to price signals, therefore VoLL is a de facto demand side bid which is set at an order of magnitude above the usual price and is deemed to represent the value of involuntary load shedding; and
- removing VoLL would increase the risk to participants and undermine the stability of the market which would ultimately lead to higher costs being borne by end customers.

They claim that without a price cap there would always remain the (slim but real) possibility of a generator offering a price that would be sufficient to bankrupt customers. Should such an incident occur the cost of disclosure to the industry would be enormous and insuring against the costs of such an eventuality would impose unnecessary and additional costs on customers that would be against the public interest.

Macquarie Generation is of the view that rather than VoLL being set at $5000/MWh in the NEM, a more reasonable level for the price cap would be $1000/MWh, which was the price in use in New South Wales at the time Macquarie Generation made its submission.

The Tasmanian Government argues that the ceiling price limit is, on balance, a desirable feature from the viewpoint of limiting financial exposure for participants during the establishment of the market. The Tasmanian Government believes that the market should ultimately set the spot prices at all times, apart from arrangements that will be necessary when the market is suspended. They state that the elimination of the ceiling price should be considered by the Reliability Panel in its review of the value of VoLL.

TransGrid states that the price cap is reasonable. It notes that the cap is meant to be an interim arrangement whilst participants become familiar with risk management arrangements. The SMHEA argues that in time the price cap should be replaced by a market based approach.

The EUG considers that VoLL is questionable on competition grounds as it sets a maximum price in the spot market. It adds, however, that VoLL does provide participants with some certainty in the form of an absolute cap on pool prices, which could be important in the early years of the NEM. The EUG states that it is difficult to judge whether the proposed level of VoLL strikes the right balance between these conflicting issues, and accordingly is of the view that VoLL needs to be closely monitored. Boral Energy also supports a continual review of VoLL.

What the applicants say

The applicants state that in an ideal world a price cap would not be necessary. In such a case participants would have the capability to ensure that they did not buy or sell in the event that the market clearing price did not meet the price threshold they had previously indicated. In the context of an electricity market this would require all generators and wholesale buyers to have the physical capability to control their generation or purchases at all times to match their indicated intentions in the form of bids and offers into the spot market. The applicants argue that this is not practical because:

- many generators have physical constraints which limit their ability to respond instantaneously to changes in market price; and

- very few wholesale purchasers have the capability to directly control the amount of demand they are taking from the market at any point in time (many retailers do not have the real time load monitoring and remote load control system to allow them to directly manage their wholesale purchases).

Accordingly the applicants state that with demand side participation in the scheduling and dispatch process being purely optional, there is no guarantee that the spot market will physically clear at all times. Therefore, the market operator must have the authority to direct customer load to be cut off when necessary to protect the integrity and security of the power system. However, the wholesale purchasers whose load has been interrupted will not have submitted a dispatch bid indicating a bid price at which it would be prepared to have that load interrupted. Instead the Code sets the price at such times to a specified maximum amount, VoLL.

The applicants claim that due to information asymmetries and technology shortcomings for market customers there is no practical alternative under the current market design to imposing a price cap.

In relation to the level of this price cap, the applicants assert that there is no single theoretically correct level of VoLL. Accordingly, VoLL is a necessarily simplified value to use in place of the potentially wide range of possible values which affected customers would apply given the opportunity to do so.

The applicants state that if VoLL is set too low it will materially impact on the overall level of power system reliability as it would discourage investment in new (and possibly mothballing of existing) high operating cost peaking plant which provide essential reserves for the overall market.

If VoLL is set too high it would substantially increase the risks associated with the occurrence of such high prices and would probably result in over-investment in reserve plant and voluntary load interruption schemes.

The applicants argue that the level of VoLL proposed in the Code, which is consistent with the value currently in use in the England/Wales market, strikes a balance between these two conflicting needs.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.5 Clause 3.9.4 must be altered to allow yearly reviews of the value of VoLL, specify that VoLL will not decrease and allow changes to the value of VoLL to take effect within 30 business days of notification.

At the pre-decision conference and in submissions, the applicants and numerous market participants raised concerns about the proposed notification period for changes to VoLL.

The incumbent Victorian generators note that the value of VoLL is the single biggest contributing factor to participants' ongoing assessment of their risk position, and their contractual, bidding and operational responses to the management of risk. In this context, it is argued that 30 business days is insufficient time for market participants to adjust their risk positions, given that the electricity contract market is primarily long term focussed (one year or more). Suggestions for a more appropriate notification period range from six months to two years.

The requirement prohibiting decreases in VoLL is not supported by CitiPower, the EUG, Integral Energy, Powercor, Solaris and TransGrid. They argue that this requirement is unnecessarily restrictive and limits flexibility in the future. CitiPower notes that VoLL is presently an arbitrary number used as a surrogate for demand side response that would otherwise clear the market and it is conceivable that it may need to be reduced to reflect the true value of curtailment to retail customers. In contrast, SMHEA takes the view that VoLL should be interpreted as a price cap rather than a default demand side bid. On this approach, SMHEA argues that the price cap should be raised as quickly as practicable to a level at which it will not impede market clearing and that the Code should be amended to prohibit decreases in this level.

Commission considerations

The main rationale for the price cap is to ensure the market is not subject to large price shocks, particularly in the transitional phase of the NEM.

As noted by the applicants the level of VoLL is critical. VoLL restricts market outcomes by placing an upper bound on the prices, and hence revenues, that a seller in the market may earn, and in so doing can distort the market value of electricity. It may also encourage generators to game the market and force the spot price to VoLL, but if this occurs it may encourage additional generation to be made available to fulfil demand in order to take advantage of higher spot prices.

A value of VoLL set too low may result in insufficient generation capacity being available in periods of excess demand resulting in intervention by the market operator. If the price cap is too low it may also affect long term investment signals. For example, if the spot price is capped at too low a level investment in peaking, standby and other generation plant, or equivalent demand management techniques may be less than they would otherwise have been, and existing facilities in these categories may be disadvantaged.

The extent of market distortions will depend on the frequency of 'price spikes' great enough to induce the price cap and the likely duration of such events. If these events are relatively infrequent and short lived the distortionary effect of the price cap will be minor.

The general perception is that an excess demand situation is an unlikely event given existing over-capacity, and as such the price cap may have little impact on overall market outcomes in the short term. In fact since the commencement of the NEM1 Stage 1 on 4 May 1997, weekly time weighted spot prices have not exceeded $113/MWh in either the New South Wales or Victorian pools.[52] Prior to the commencement of the NEM1, however, the pool price in Victoria peaked at $3567.90/MWh on 14 January 1997. Such price spikes occur extremely infrequently. Even on this day the time weighted average spot price, while high, was still under $140/MWh.

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52 Approximate maximum spot price ($MWh) from 4 May 1997 to 9 August 1997.

Thus the current difference between VoLL and the pool prices in Victoria and New South Wales indicate that the value of VoLL in the NEM is sufficiently high that it is unlikely to distort market outcomes. However, the Commission notes that a review by the Victorian Pool Consultative Committee is considering whether the VicPool rules prevented the price going to VoLL. The current pricing outcomes also reflect the excess supply situation in New South Wales and Victoria, making the probability of reaching VoLL less likely.

The Commission is aware of a study conducted by Monash University which recommends a significantly higher value of VoLL than the present figure. Given that this present figure is arbitrary and may increase significantly in the future, the Commission accepts that prohibiting decreases in the value of VoLL is unnecessarily restrictive.

Without a price cap customers in particular may be exposed to price shocks and potential bankruptcy. However, exposure to VoLL will be reduced to the extent that customers are able to hedge against such price risk, for example using bilateral contracts and the STFM. The Commission recognises that VoLL is a crucial element in the risk position of all market participants and accepts the view that 30 business days is too short a notification period for major changes to the level of VoLL. Several participants put forward the view that at least six months notice is required and the Commission has decided to alter its condition of authorisation to reflect this view. As excess capacity is reduced, the probability of reaching VoLL will increase. Nevertheless, by the time excess capacity is eroded it is anticipated that customers will have sufficient experience of market operations to implement hedging and develop demand side responses.

It may be that in future as the NEM matures, VoLL might not be required. The Commission is aware that the New Zealand electricity market operated under a price cap of $NZ150/MWh until 1 October 1996. The reason the cap was removed was that spot prices never reached this value, except during the 1992 drought. Therefore, as in New Zealand, the price cap may only be needed as a transitional measure to protect customers in the early stages of the NEM.

Overall, there is a public benefit in having VoLL as it protects customers against price spikes that may arise in periods of excess demand. This is an important consideration given that the NEM is a new market arrangement where demand side responses to high prices are expected to take some time to develop.

Although the current value of VoLL is arbitrary the Commission is not in a position to recommend the appropriate level. Instead, the Commission accepts the current level of $5000 and anticipates that a revision will occur within 12 months of market commencement. This is based on the results of the Monash University study and comments from market participants. The Commission also acknowledges that an increase in VoLL may be necessary to help resolve Victoria's lack of reserves in the summer peak (for further detail, refer to section 9.2.1).

While there is to be a review of the value of VoLL by the Reliability Panel within one year, there are no provisions in the Code which ensure a regular review of VoLL. The Commission believes that the measures in the revised New South Wales Code and the revised VicPool Rules for the operation of the NEM1 Stage 1 would appear to provide a sound framework for such reviews of the value of VoLL.

Condition of authorisation

C8.5 (a) Clause 3.9.4(c) must be amended to provide for the Reliability Panel to conduct yearly reviews of the value of VoLL; and

(b) Clause 3.9.4(d) must be amended to provide that changes to the value of VoLL must take effect six months after notification.

8.7 Floor price

In the NEM, generators will be operating under conditions where they are responsible for determining the level of electricity they wish to sell into the market. Accordingly, a situation may arise where too much plant has elected to self-commit for the expected/actual demand, resulting in excess generation. Large thermal power stations incur considerable costs if they are required to completely stop and later restart their boilers, or face a potentially dangerous situation if they generate at below their minimum output level. At particular times when demand is very low the situation may arise where thermal generators are willing to offer prices of zero or below in order to guarantee dispatch, because the cost of decommitment and subsequent restart are significantly greater than the short term cost of remaining operational at zero or negative prices. Such a situation is called an excess generation period.

To solve this problem without direct intervention by the market operator, the Code prescribes a pricing mechanism whereby generators submit negative prices which represent the price they are willing to pay to remain on-line. However, the Code constrains spot prices to be not less than zero for customers during excess generation periods (clause 3.9.6). This asymmetry in spot prices between suppliers and customers will result in an accumulation of funds by NEMMCO.

Issues for the Commission

The main issue for the Commission concerns the imposition of a floor price for customers of $0/MWh during periods of excess generation. This floor price may constitute a price fixing arrangement in breach of s. 45 of the TPA. These arrangements may detract from the overall public benefit of the market in that they will distort market signals.

What the interested parties say

The SMHEA and the Tasmanian Government both argue that the floor price is essentially an anti-competitive form of price fixing and that customers should be charged the negative price that generators see, not the floor price of $0/MWh. In the Tasmanian Government's opinion negative prices are unlikely to be a persistent feature of the market and are sending necessary signals if they do occur.

Northparkes Mines contends that there should not be a floor price in the NEM so customers are able to obtain the full benefit of an open market.

The EUG states that the efficient functioning of the NEM requires that customers be given the flexibility to take full price advantage of excess generation situations. It adds that if the floor price remains NEMMCO needs to clarify how money accumulated in periods of excess generation will be dealt with. Australian Paper similarly argues that the benefits of negative price bids should flow to the market, and money should not be accumulated in a 'slush fund'.

EnergyAustralia argues that the imposition of a floor price is necessary to avoid the absolute waste of electricity. It adds that while a negative pool price is environmentally unpalatable, none of the funds accumulated as a result of the floor price should be returned to generators.

The Victorian DBs argue that if the pool price is set at zero, moneys accumulated in an excess generation fund should be reimbursed to retailers.

VPX and Yallourn Energy support the applicants' proposals in conditions of excess generation, while Delta Electricity, although supporting the use of negative bid prices during excess generation periods, favours generator to generator compensation being introduced rather than the creation of an excess generation compensation fund.

What the applicants say

The applicants argue that the best mechanism to reduce the supply of generation during a period of excess generation is for spot prices to be constrained to be zero for customers, with an obligation placed on generators to submit negative price bids to enable them to continue to generate. This approach, the applicants argue, will send a strong signal to all generators to avoid a period of excess generation. It will also allow the market to resolve the excess generation problem rather than have the market operator resolve it in some arbitrary manner.

Limited capability for a demand side response

The number of customers who would be able to respond to negative pool prices, in real time or with a short lead time of 1–2 hours, is limited to those who are directly exposed to pool prices and have the ability to increase their consumption. The vast majority of end use customers who elect to have pool price exposure are limited in their ability to increase consumption at low or negative pool prices. Therefore, the applicants assert that a negative pool price to customers, in the short term, may only have a limited impact in increasing demand to avoid the excess generation problem.

A generator problem

The applicants state that an excess generation condition means that even when the spot price of electricity has fallen to zero, collectively generators are still unwilling to reduce their output to match demand at that price, even though generation must be reduced to avoid a system collapse. They add that it is extremely unlikely that an increase in demand can occur which might contribute to solving the excess generation condition in the short term.

The applicants contend that allowing the pool price for generators to be less than zero while pegging the pool price to customers at zero maximises the incentive for generators to reduce their output. It ensures that contracted generators will not receive difference payments under their contracts from customers which simply offset the payments to the pool resulting from the negative pool input price. Therefore, all generators, not just those which are uncontracted, will pay a penalty for continuing to generate. Also, under a negative spot market price market customers may face increased risk if they were over contracted, because they would then face payments to generators without an offsetting revenue stream.

Accordingly the applicants state that allowing a negative price to generators with a pool floor price to market customers of zero will result in excess generation periods occurring less frequently than would otherwise be the case. It also ensures that when they do occur there is less need for intervention by the market operator. They state that this is clearly in the public interest.

Prudential risk and market complexity

The applicants argue that for parties to a bilateral contract which references the pool price, the maximum difference payment a purchaser will ever have to make under the contract will be limited to the strike price of the contract. If the reference price for the contract could be less than zero without any limit, it would create another complex set of risk management issues which participants will have to address. The applicants argue that the arrangements are an essential feature of the market as long as there is no compulsory demand side bidding with the physical systems in place to enable every market consumer to be dispatched.

Accordingly, the applicants argue that the floor price provides key incentives to generators while protecting customers.

Issues arising from the draft determination

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

C8.6 Clause 3.9.6 must specify that the zero dispatch price during an excess generation period will only apply for one year from the commencement of the NEM.

C8.7 The Code must be amended to ensure that any money received by NEMMCO during an excess generation period must be paid to market customers.

NEMMCO must develop a methodology for distribution by it of monies received during an excess generation period to market customers and must incorporate the methodology into the Code.

In their supplementary submission, the applicants indicate that NEMMCO would prefer not to have to build a system that would be in place for one year, but considered this to be a better solution than the removal of the floor price at market commencement. They also note that the removal of the floor price will change market participants' risk profiles and time would be needed to manage these changes.

The ACA, BCA/EWG, Delta Electricity, Macquarie Generation and Solaris support the removal of the floor price.

The ACA states that, in the longer term, removal of the floor price will signal the correct demand behaviour of moving peak electricity consumption to 'off peak', thereby better utilising system assets. Delta Electricity and Macquarie Generation indicate that the floor price should be removed to allow an unimpeded supply and demand response in the market, while Solaris considers that removing the floor price effectively poses no additional risks or costs on the industry.

Boral Energy, Eastern Energy, energyAustralia, Integral Energy, Loy Yang Power, Southern Hydro and Yallourn Energy oppose the removal of the floor price.

Boral Energy and energyAustralia consider that negative prices give a perverse and environmentally-unsound incentive for consumers to be paid to use more energy. Boral Energy adds that zero prices should be a sufficient driver to increase demand.

CitiPower argues that if the floor price is to remain for the current tranche of vesting contracts, it should remain until December 2000, which is when current Victorian contracts expire.

Integral Energy and Boral Energy note that allowing negative pool prices changes the risk profile of the market considerably. Eastern Energy adds that the perverse price signals would impose additional risk to the demand side of the market (to meet potentially high contract payments).

Loy Yang argues that negative prices will make generators indifferent to remaining on or offloading, at least to the extent that they have contract cover, which will weaken or remove the signals to generators to solve the excess generation problem. This view is supported by Yallourn Energy and Southern Hydro.

Pacific Power put the view that there should be a floor price but it should be set equal to negative VoLL.

Most parties support the requirement that excess generation funds be returned to market customers.

Commission considerations

The Commission is of the view that not allowing market customers to see negative prices has significant anti-competitive effects that impact upon the efficiency of market outcomes.

Firstly, customers are denied the market benefits of negative prices at times of very low demand. In a market where customers are exposed to positive pricing outcomes in times of high demand there is generally no justification for asymmetry in the rare event of a negative price outcome.

Secondly, non-negative pricing distorts price signals by not allowing the market to function unimpeded and formulate an appropriate response. Prices are a signalling mechanism to customers; if customers are not exposed to appropriate pricing then the efficiency benefits arising from changing demand patterns are lost.

Each of the arguments put forward by the applicants is analysed below.

Limited capability for a demand side response

The Commission accepts that at present demand side responses are immature. The NEM is a new market mechanism and electricity has not been traded in this way in the past. Many customers do not currently have the ability to increase their consumption of electricity in response to negative prices. Accordingly, this argument will lose much of its cogency once customers become familiar with the operation of the NEM. For example, customers may employ load shifting to take advantage of negative prices. In the meantime, however, the Commission acknowledges the applicants' concerns regarding the present limited demand side response possible in the NEM.

A related issue concerns the distribution of money paid to NEMMCO in an excess generation period. The Code refers to the fact that participant fees may be adjusted in light of payments received by NEMMCO in periods of excess generation (clause 2.12.1(c)). The Commission considers that a system whereby generators pay NEMMCO to continue generating in excess generation periods can only contribute to addressing an excess generation problem if money received by the NEMMCO is not used to reimburse generators. If some of the money is returned to generators in the form of lower pool fees the Commission questions the impact that such a clause would have in addressing problems of excess generation. The Commission considers that more efficient market signals would arise from rebating money accumulated to market customers.

A generator problem

The applicants argue that exposing consumers to negative pool prices would allow contracted generators to pass on the costs of an excess generation period to consumers. If a contract for differences is based on the spot price, then in the event of an excess generation period, a customer will be required to pay the absolute difference between the strike price and the negative spot price. It was further argued at the pre-decision conference and in submissions, that this would weaken or eliminate signals to generators to solve the excess generation problem.

The Commission is of the view, however, that customers with contracts would be unlikely to agree to be exposed to negative spot prices. Knowledgable customers would be aware that under a contract for differences the customer would be required to pay the generator difference payments which would more than offset the amount that the generator would have to pay into the pool to remain generating (the absolute difference between the strike price and the negative spot price). In such circumstances a customer would be aware that it is effectively paying the generator to keep producing. The customer would therefore be extremely reticent to contract with a generator where the price is allowed to go negative, as they would be taking on the generator’s risk in times of excess generation. Rather, customers would tend to enter into contracts where they would not be as exposed to negative pool prices. The argument of the applicants therefore appears to assume a lack of knowledge of the operation of the market on the part of customers.

The Commission notes Boral Energy’s comment that ‘consideration of contracts for differences, to which customers are generally not a party, is inappropriate and does not address the issue of this being a generator problem.’ The Commission acknowledges that at the present time most contracts are between generators on the one hand and retailers, rather than end-use customers, on the other. However, this fact would appear to reinforce the argument that generators’ ability to pass on the costs of excess generation periods will be constrained by knowledgable contracting counterparties.

Prudential risk and market complexity

The applicants argue that a complex set of risk management issues is created by allowing negative prices. It is claimed that customers and generators would need to factor some form of risk sharing or management into their contracts for the possibility of a negative pool price occurring. However, given the many financial instruments available in the market it is unlikely that risk management will impose significant complexity for participants.

The Commission considers that any perceived complexity introduced into the settlement process is insufficient to justify precluding customers from benefiting from negative prices. The Commission is not convinced that added complication will be brought into settlement, since the settlement function already has to consider negative prices for generators.

Other arguments

It has been argued that removing the floor price would have implications for contract positions, since the value of existing contracts will change if the pool price is calculated using a method not involving a floor price. The Commission considers that this argument has some validity at present, but will become less relevant in coming years, particularly as existing vesting contracts expire. Market participants have some time before the floor price is removed, in which to re-negotiate their contract positions.

A further argument against removal of the floor price is that negative prices would present a poor or inexplicable picture to the public in that they may be interpreted as paying customers to consume electricity. However, spot prices form only one component of delivered electricity prices. Where spot prices are negative, transmission and distribution charges still mean that the prices customers see will most likely be positive. Moreover, negative prices need not encourage the waste of electricity but may have a beneficial effect in terms of load shifting and the development of demand management tools.

Conclusion

Of the arguments in favour of a zero floor price for customers in periods of excess generation, the Commission firstly accepts the applicants' view that the demand side response to negative prices may presently be immature. The Commission, however, is of the opinion that over time the ability of customers to respond to negative prices will develop, as customers' knowledge of the operation of the market improves.

The Commission also acknowledges the concerns raised over existing vesting contracts, but believes that participants have sufficient time to re-negotiate contracts to match their desired risk positions.

Accordingly, the Commission believes that if a zero floor price is to be introduced it should be an interim measure only.

Further, the Commission is of the view that money paid into an excess generation fund must be returned to customers. Such a measure would provide effective market signals and would also ensure that customers are protected.

The applicants have responded to the Commission's concerns and have agreed that money accumulated during an excess generation period should not become part of the NEMMCO budget. Further, they state that NEMMCO is currently working on a methodology to distribute funds accumulated during an excess generation period.

Conditions of authorisation

C8.6 Clause 3.9.6 must be amended to provide that the zero dispatch price during an excess generation period will apply for only one year from the commencement of the NEM.

C8.7 The Code must be amended to provide that:

(a) any money received by NEMMCO during an excess generation period must be paid to market customers;

(b) **NEMMCO must develop a methodology for the calculation and prompt distribution by it of money it receives during an excess generation period, to market customers entitled to that money;**

(c) **NEMMCO must pay the market customers entitled to that money as soon as possible, and in accordance with that methodology; and**

(d) **the methodology must be incorporated into the Code.**

8.8 Short term forward market

Clause 3.10 of the Code requires NEMMCO to facilitate the establishment of a short term forward market (STFM). The purpose of a STFM is to provide for adequate means of price discovery in the days leading up to spot trading and thereby enable market participants to manage and adjust their risk exposure. The STFM is also intended to assist the market to arrive at an efficient balance between committed generation and expected demand across the interconnected power system. This will preserve system security while minimising the need for central intervention through, for example, the reserve trading provisions.

Issues for the Commission

The Commission is concerned that if NEMMCO itself is to provide the STFM this may prevent or discourage other service providers from establishing alternative STFMs. Conflicts of interest may arise if NEMMCO both conducts the STFM and takes a position in it. The situation may arise where NEMMCO has access to information which could enable it to unduly influence the market for one of its other functions, such as the IRH exchange.

What the interested parties say

The majority of submissions which discuss the STFM arrangements raise concerns about NEMMCO's role as STFM operator.

The first concern is that there is a potential conflict of interest between NEMMCO's role as market operator and its role as operator of the STFM. Macquarie Generation argues that there is a potential conflict of interest in NEMMCO operating a market where its financial position determined by that market could be affected by the outcomes of the physical market that it is also operating under the Code. Similar conflict of interest concerns were raised in submissions from Macquarie Bank, the EUG, Boral Energy, Ecogen Energy and TransGrid.

The second concern is that NEMMCO should not establish a STFM because market based arrangements are likely to develop outside the pool management framework. This view was put forward by Macquarie Bank, the EUG, Macquarie Generation, the New South Wales Electricity Reform Taskforce (ERTF), Boral Energy, Integral Energy, the Victorian DBs, Delta Electricity and TransGrid. They argue that normal financial market makers and electricity market participants will develop their own solutions to the need to trade contracts in the short term. They claim that such solutions are already developing in New South Wales and would have the added benefit of not exposing NEMMCO to risk. It is further argued that provision of the STFM by NEMMCO would deter alternative suppliers of such a service.

The SMHEA argues that the STFM allows the market to operate effectively as it enables participants to adjust their contract positions in light of changes in their circumstances. It does not specifically comment, however, on who should operate the STFM.

What the applicants say

The applicants submit that it is vital that services such as a STFM are available because they enable market participants to better manage risk. They assert that there would be substantial detriment to the operation of the NEM if this sub-market did not develop. Therefore, the establishment of the STFM cannot be left to chance in the early developmental phase of the NEM. In addition, the potential for private sector involvement is fully recognised by the Code as nothing in the Code precludes other persons from offering these services to NEMMCO or to other persons.

They further state that if NEMMCO itself operates a STFM it must ring fence its trading activities by keeping separate accounting records with clear audit trails for each trading activity. This will ensure that in managing the STFM NEMMCO uses no advantage derived from its other functions which would not be available to an alternative operator.

In considering concerns about NEMMCO's STFM function the applicants argue that it must be recognised there is a three year sunset clause for NEMMCO's facilitation role. Indeed, whether NEMMCO should have any future role in the STFM will be reviewed by NECA within two years of market commencement.

The applicants add that if an alternative STFM develops before the sunset clause becomes effective, then Code change processes may be used to amend NEMMCO's role.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.8 Clause 3.10 must be deleted.

While this issue was not raised at the pre-decision conference, Boral Energy, CitiPower, Eastern Energy, Integral Energy and Solaris provided submissions supporting the view that NEMMCO should not operate the STFM.

Boral Energy agrees with the applicants' statement that risk management instruments must be available for the market to function correctly but stated that the financial market is more than capable of providing such instruments. However, Solaris noted that while the instruments developed so far have been adequate for the level of risk in the market, it is not correct to say that adequate instruments have been developed to handle a price cap of perhaps four times the present level, which may be the case once domestic load becomes contestable and vesting contracts disappear.

SMHEA stated that while the deletion of clause 3.10 may improve the prospects that competitive provision of STFM services will eventually arise, it may reduce the efficiency of the NEM in the interim. Without a STFM, participants can only adjust their short term positions through bilateral contracts which have a number of difficulties including identifying potential counterparties, price discovery and management of prudential risk. These difficulties are likely to be more severe for smaller players.

Dr Hugh Outhred states that while entities other than NEMMCO may be well positioned to implement the financial forward market function, it is much less likely that they could implement an effective STFM, which should in principle be a gross auction market for all spot market participants. Ideally it would be solved by the same auction algorithm and network model used for the spot market.

Commission considerations

The Commission is of the view that there is considerable public benefit in having an efficiently operating STFM. The STFM facilitates and provides the economic signals for the decentralising of commitment and decommitment decisions to generating plant owners rather than some central body. It also allows participants to trade to their optimal positions. This ability to trade to minimise risk is likely to be a particularly relevant consideration for slow start generators. Given that inappropriate commitment (starting up and then not being dispatched) may be very costly, and inappropriate non-commitment may lead to large opportunity costs and even inadequate power supplies to users, removal of such uncertainty increases economic efficiency.

The STFM also promotes demand side participation in the market. Where market customers have no real flexibility to move their electricity demand within two days of the actual time of usage, it allows them to minimise their exposure to spot prices by adjusting their overall contract position. Where customers do have some flexibility it provides them with an opportunity to adjust their plans in response to prices in the forward market and lock in the benefits through forward contracts.

Accordingly, the Commission is of the view that an efficiently operating STFM has public benefits.

The other issue for the Commission is whether the STFM should be provided by NEMMCO or left to private sector development. There are a number of arguments in favour of central provision of the STFM. First, the private sector may only offer hedges in large regions, thereby discriminating against participants outside such regions. Second, private provision of the short term forward contracts would effectively increase participants' prudential requirements. Not only would participants have to meet the prudential requirements in the Code but also those imposed by any private sector provider. Third, there is potential for insider trading with private provision of short term forward contracts. For example, a generator may not reveal an outage to the market, or may take a position in the market before it does so. In such circumstances a generator may be financially advantaged. Fourth, if there is no central provision of a STFM there may be numerous providers of such a service, which could create a market lacking in depth and liquidity. Finally, there is the argument that an effective STFM should be a gross auction market which is solved by the same algorithm and network model used for the spot market and therefore NEMMCO is the appropriate operator.

While accepting some of these arguments the Commission still questions whether it is appropriate that NEMMCO provide these services.

First, the Commission is of the view that conflicts of interest may arise between NEMMCO's role as market operator and its other trading functions. This may be the case if NEMMCO offers a STFM which also utilises IRHs, while simultaneously taking a physical position in the wholesale market through contracting for reserves and ancillary services. Indeed, even if such conflicts of interest are controlled by the means outlined in the Code, the perception that they exist may be of ongoing concern.

Second, the Commission considers that a STFM may be capable of development outside the pool management framework. The Commission notes Solaris' comments that existing risk management instruments would not be adequate to handle the increase in risk levels likely to occur in the future. It also notes SMHEA's view that deleting clause 3.10 may reduce the efficiency of the NEM in the short term. However, the Commission acknowledges the progress being made by the New South Wales market participants in the development and trading of standard financial instruments based upon the International Swap Dealers Association documentation. These initiatives indicate to the Commission that a viable STFM is likely to be capable of development independently of NEMMCO. The Commission favours this approach as it would appear to deliver the public benefits attributable to the STFM, without the same potential for conflicts of interest, and therefore anti-competitive detriment, as a NEMMCO-operated STFM.

The applicants have responded to the Commission's concerns and agreed not to pursue a facilitated STFM, and have stated the Code will be amended accordingly.

Condition of authorisation

C8.8 Clause 3.10 must be deleted.

8.9 NEMMCO provision of inter-regional hedges and the settlements residue

8.9.1 Provision of inter-regional hedging

Where electricity is traded between regions, market participants may be exposed to significant risks arising from variable spot price differences between regional reference nodes. Such risks can be managed through the use of instruments referred to as inter-regional hedges (IRHs).[53]

Under clause 3.11, NEMMCO is to ensure that an IRH exchange is established to facilitate trade in IRH contracts by market participants. NEMMCO's facilitation of this exchange is to cease within three years (clause 3.11.2(e)) unless a NECA review recommends otherwise (clause 3.11.2(f)).

Issues for the Commission

The clauses relating to IRHs may breach s. 45 of the TPA because:

- NEMMCO's access to settlement surpluses to underwrite hedges may lessen competition;
- NEMMCO's obligation to set a reserve price for its hedges may be a price fixing arrangement;
- NEMMCO's ability to contract with NSPs and/or ancillary service providers can significantly affect the capacity of interconnectors and therefore regional pool prices. The knowledge that NEMMCO has this power may affect the degree to which other parties will contract to provide equivalent hedges and thus lessen competition; and

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53 Inter-regional hedges are financial instruments such as options and swap contracts which hedge inter-regional spot market differences. An IRH provides the holder to the rights to inter-regional price differences for a fixed quantity.

- NEMMCO may engage in secondary trading in IRHs even where it is the entity that establishes and administers the exchange. If NEMMCO were to use information gained from its special position in the market in its secondary trading this would affect the confidence that participants and other parties have in the market, and it may be anti-competitive. Likewise, if NEMMCO obtained special treatment from the exchange administrator this would also affect the confidence that participants and other parties had in the market, and this may also lessen competition.

What the interested parties say

The EUG, TransGrid and Ecogen Energy support the need for NEM participants to have access to an IRH market. The SMHEA contends that the current proposal in the Code allows for the market to operate effectively and be non-discriminatory towards inter-state contract trade.

Ecogen Energy, Macquarie Bank, energyAustralia, Integral Energy and Boral Energy all state they have a preference for a market based solution rather than just directing NEMMCO to develop or even facilitate an IRH exchange. Integral Energy and the Tasmanian Government contend that while NEMMCO maintains the facility it may stifle the market development of innovative financial products and services.

Delta Electricity and the Victorian DBs recommend that NEMMCO withdraw resources from this area after a transition period.

Macquarie Generation is of the opinion that it is not clear whether the current proposal is the best solution and other options for handling the issue of inter-regional trade should be considered.

Concern over complexity of the IRH arrangements was raised by Macquarie Bank and Macquarie Generation. Macquarie Bank states that while it sees the desirability of clause 3.11[54] remaining, it thinks clauses 3.11.1(b),[55] 3.11.2[56] and 3.11.4(a)(3)[57] should be removed. Further, it is suggested that a clause be inserted to require NEMMCO to sell inter-regional contracts with the sole purpose of managing risk and not developing inter-state trade and that NEMMCO should only offer contracts once a year to minimise market inefficiencies. It also believes that clause 3.11.3[58] should be amended to require that NEMMCO can only trade in the secondary market when physical constraints or changes occur.

The SMHEA, Ecogen Energy, Integral Energy, TransGrid, the Victorian DBs, Macquarie Bank, EUG, Boral Energy and the Tasmanian Government are all concerned that NEMMCO has a potential conflict of interest by having trading activities which include the inter-regional trader.

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54 Clause referring to inter-regional hedging.

55 NEMMCO must ensure that IRH contracts are made available for purchase by market participants in respect of all interconnectors for which settlements residues are allocated to NEMMCO in accordance with clause 3.11.1(a).

56 Clause referring to development of an IRH exchange.

57 Clause referring to NEMMCO's inter-regional trading accounts specify that NEMMCO must separately account for all moneys applicable to its facilitation of the IRH exchange.

58 Clause referring to NEMMCO undertaking secondary trading in IRHs.

What the applicants say

The applicants emphasise the IRH arrangements in the Code are part of a total package. They say all aspects of the package are closely interdependent and it is not possible to delete one aspect of the package without having a potentially significant detrimental effect on the whole.

The applicants acknowledge some of the provisions of the Code described above have the potential to be a barrier to other providers of IRHs or IRH exchanges. But they say that the cost of a failure to provide IRHs or an IRH exchange is likely to be a number of orders of a magnitude larger than the benefits of additional competitive IRH participation at market inception.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.9 Clause 3.11 must be deleted.

Boral Energy, CitiPower, Eastern Energy, energyAustralia, Integral Energy, Macquarie Generation and Solaris support the condition of authorisation. Both Boral Energy and energyAustralia state that the financial markets are capable of providing adequate risk management instruments.

The EUG states that there are enough doubts about the development of a market to warrant monitoring of the situation by NEMMCO in the initial phases of the NEM, with a requirement to report back to the Commission and NECA.

Delta Electricity and EME oppose the deletion of clause 3.11. Both parties note that while the market has been prepared to offer IRHs up to an amount which directly balances the counterparty's exposure in the other State, no market exists for options for inter-regional price caps. They state that the absence of such options reduces contract trading between regions and insulates regional markets from competition.

SMHEA expresses concern about a satisfactory alternative to clause 3.11 being put in place before commencement of the NEM. It notes that IRH arrangements are critical both to realising the benefits of a national market through removing existing barriers to inter-state trade, and in relation to the Snowy Hydro Trading's (SHT) ability to trade in the NEM. It suggests that the existing arrangements be allowed to stand until new IRH market arrangements are in place, a view supported by SHT.

The Victorian Government also notes than an IRH market is a vital component in stimulating competition across all States in the NEM and favour further consideration of options involving the facilitation of an IRH market, whether by NEMMCO or an alternative hedge provider with access to the settlements surplus.

Dr Hugh Outhred notes that IRHs play an important role in the STFM timescale, providing guidance as to the anticipated level of inter-regional flows as well as hedging functions.

Pacific Power put the view that provision of IRHs by NEMMCO or anyone else does not solve the basic problem which is that money paid for energy by retailers in the importing region is not passed on to the suppliers of that energy.

Commission considerations

From the Commission's perspective there are two questions that need to be answered.

- Firstly, is there an efficiency or prevention of market failure argument for the provision of some or all of this service by a monopoly entity, or could some or all of it be provided equally efficiently by market based private sector organisations?

- Secondly, if a conflict of interest can arise in the provision of the function by either NEMMCO or a private operator, what should be done to eliminate or minimise that situation?

In assessing the first question the Commission accepts that inter-regional trade is important to the overall integrity and efficiency of a national market for wholesale trade in electricity. Inter-regional trade can enhance competition by adding competitors to the regional markets. Arrangements to write and trade financial contracts by participants in the NEM will be enormously important to ensuring efficient market signals and providing participants with the ability to efficiently manage their risks.

In a competitive market transport rentals arise from the conveyance of electricity from low priced to higher priced regions. Parties in receipt of settlements residues associated with an interconnection are natural providers of IRHs to the extent that the settlements residue matches hedge payouts. However, although the concept of a non-regulated interconnector is allowed for in the Code, all existing interconnections are part of regulated network businesses which will be fully funded through network service charges. The Commission accepts that this means that the NSPs have no incentive to provide IRHs, and this lack of a natural provider of hedges has been identified as the market failure warranting central provision.

Accepting that IRHs are important to the development of an integrated NEM, the Commission notes that there are three options:

- central provision as proposed in the Code;

- facilitated provision of IRHs; and

- no central or facilitated provision of IRHs.

Central provision

Central provision may correct a market failure, however, the provisions in the Code raise a number of issues and concerns.

The Commission and some interested parties contend that the Code provisions are extremely ambitious, and may not represent the minimum required in order to commence a market in IRHs.

It can be argued that NEMMCO has no financial interest in the IRH market since it does not retain IRH profits nor any profits obtained from conducting an IRH exchange. It is intended that NEMMCO will use its IRH trading arrangements, particularly trading in the secondary market, to mitigate its risks. The difficulty here is that NEMMCO may not have sufficient incentive to conduct its secondary trading efficiently or manage risks effectively, raising the danger that the market may be open to an unacceptable level of risk. Despite the Code's accountability provisions there is still a concern among interested parties that conflicts of interest may arise between NEMMCO taking on the provision of IRHs and NEMMCO no longer being an impartial operator of the market.

Facilitation of IRHs

This option involves an entity other than NEMMCO undertaking the task of designing, issuing, pricing and settling IRHs. While such facilitated provision of IRHs addresses concerns about potential conflicts of interest between NEMMCO roles, it raises a number of other issues such as governance and the concerns associated with access to the settlements residue.

The Commission is aware of a proposal developed by NEMMCO and its consultants Putnam, Hayes and Bartlett (PHB), under which NEMMCO would take a minimum facilitation role in encouraging the provision of IRHs underwritten by the settlements surplus. NEMMCO's public consultations on this proposal revealed no clear consensus of opinion and identified a number of related issues including regional boundary definitions, allocation of settlements surplus, firm access arrangements and transmission pricing. NEMMCO has indicated that it will not be progressing the facilitation of IRHs at this point in time.

No facilitation or central provision

A number of interested parties, such as Boral Energy and energyAustralia, feel that the market's ability to design instruments to hedge against risk should not be underestimated. They refer to the existence of swaps, options, caps and inter-regional swaps and options as evidence of financial innovation and product development to suit the needs of the newly developed industry.

However, the concern remains that what is currently being provided may not fully meet market requirements in terms of volume and liquidity.

Commission decision

The Commission considers that market based solutions should be adopted where possible, thereby avoiding contrived or centrally administered solutions, and avoiding non-commercial entities taking trading roles in the market. However, the Commission recognises that it is unclear whether a market based solution for IRHs will evolve in sufficient time, or provide the level of liquidity that the market needs at the outset.

The Commission accepts that the absence of transporters as natural providers of IRHs may mean that some form of managed solution may be needed to ensure IRHs are made available to the market in sufficient volume and at such a price that enables the full benefits of a NEM to be achieved.

Given the novel nature of IRHs there may be some justification for facilitating the emergence of trading forums, but any such facilitation should be strictly limited to the minimum necessary in order not to inhibit independent initiatives. It is the Commission's view that the current Code provisions are extremely ambitious and do not represent the minimum required. On this basis, the Commission confirms its condition of authorisation.

NEMMCO's decision not to proceed with the proposal developed with PHB is likely to mean that the NEM will commence without a facilitated IRH regime in place. While accepting that for reasons of consistency any IRH proposal should be linked in with the NECA transmission pricing review, the Commission is concerned to ensure that the implementation of a proposal is not delayed any longer than necessary.

Accordingly, the Commission recommends that the applicants develop and implement a proposal for a facilitated IRH regime within three months after the end of the NECA transmission pricing review.

Condition of authorisation

C8.9 Clause 3.11 must be deleted.

8.9.2 Settlements residue[59]

The Code requires NEMMCO to develop and publish a methodology to be authorised by NECA no later than six months prior to market commencement for the accounting, allocation and distribution of the total settlements residue. The settlements residue is due to the application of inter-regional loss factors, intra-regional loss factors and network constraints to each interconnector and each region. The methodology is to be based on the principle that the settlements residue will be allocated and distributed to the appropriate NSP and used to offset network service charges (clause 3.6.5).

Issue for the Commission

The critical issue for the Commission concerns the allocation of the settlements surplus residue. Its allocation to certain participants will send market signals which may potentially create market distortions which could lessen the public benefit of the proposed market arrangements.

What the interested parties say

A number of retailers and generators, including Delta Electricity and Macquarie Generation, state that the settlements residue should be distributed to market participants. They argue that market participants would then be in a position to use this money to underwrite their exposure to market risk, and that this would be the most effective mechanism for making regional boundaries transparent.

The SMHEA states that the settlements residue should be used specifically to reduce network charges.

The Victorian DBs assert that the adoption of NSPs as the recipients of the settlements surplus gives rise to a complex path by which surpluses find their way back to customers, which involves both significant time delays and allocational inefficiencies and inequalities. Despite the difficulties, the Victorian DBs say they do not have a satisfactory alternative which minimises complexity, and therefore recommend that the current model be retained for the time being, but be subject to a review facilitated by NECA.

TransGrid claims that the proposed method of allocating intra-regional and inter-regional settlements residues requires more detail before it is able to make further comment.

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[59] Over the course of the Code's development the settlements residue has been referred to by a number of names including: settlements surplus, black hole money and link revenue.

What the applicants say

Under the NEM electricity transport is to be a fully regulated monopoly (although the Code does have provisions for the possible future evolution of non-regulated interconnectors). The applicants say the Code approach is dictated by the present impracticality of setting up competition in the provision of transport services, and note the surplus arising from inter and intra-regional trade is a consequence of economically efficient locational signals provided by marginal loss factors.

Issues arising from the draft determination

The Commission did not impose a condition of authorisation on this issue in the draft determination. However, it did take the view that the proposal to distribute the settlements residue to end use consumers via NSPs reducing network charges is the most transparent, equitable and efficient distribution of the residue.

Delta Electricity and the South Australian Government argue that the settlements residue should be returned as directly as possible to those who have contributed to it, that is, the participants in the energy market.

The incumbent Victorian generators state that returning the settlements residue to the relevant NSP gives that NSP a perverse economic incentive to create constraint and to increase marginal loss. Pacific Power adds that these perverse incentives are not removed by paying the money to end use consumers in the form of lower network charges.

The incumbent Victorian generators also note that the most powerful use of the residue will be in underwriting risk management instruments that facilitate free trade across the regional boundaries. Similar views were put by SHT, Macquarie Generation and the Victorian Government. EME states that the timing of cash flows and the breaking up of the cash flows will make it difficult for the market to re-aggregate them into useable quantities to underwrite IRHs.

Commission considerations

When considering the NEM1 Stage 1 arrangements the Commission requested VPX to estimate the size of the settlements residue arising from inter-state trade between New South Wales and Victoria. The results indicated that the settlements residue is a highly uncertain amount, being dependent on the difference between two potentially volatile spot prices, the capacity of the interconnector, and the extent of network losses. Thus, recipients of a portion of the settlements residue are unlikely to know more than a year ahead exactly what fraction of the settlements residues they will be entitled to receive.

In deciding how to allocate the settlements residue, a key focus for the Commission in assessing the public benefit is the establishment of arrangements which deliver economic efficiency, and develop equitable solutions. Possible criteria that an allocation procedure must satisfy relate to efficiency, equity, universality of application, simplicity and transparency.

Given these criteria, a number of options have been suggested on how the settlements residue may be allocated, and these are discussed briefly below.

Return the residue through NSPs to network users via the Code provisions

Network businesses in the NEM are regulated monopolies. The Code proposes that NSPs be used as agents to transfer the settlements residue to those network users who were paying network service charges on interconnector assets. The residue must then be used to reduce transmission charges, and hence is indirectly returned to end consumers.

This mechanism was primarily chosen because the legitimate recipient of the settlements residue should be the relevant NSP. The applicants state if interconnector owners were direct participants in the spot market competing to transport electricity between regional reference nodes, the settlements residue that arose would be paid to the interconnector owner in accordance with the transport services provided. However, because NSPs will receive a regulated income they relinquish their claim to retain the residue and instead it is to be passed through to network users via a reduction in network service charges.

This mechanism for distributing the settlements residue is transparent as it will be part of the NSPs regulated income, can be universally applied, and is equitable, as consumers will receive a benefit via reduced transmission charges. It is also efficient in that it will have a minimal impact on the market while retaining economic signals. However, this approach has been criticised by some as possibly adding complexity to the market design.

Return the residue directly to market participants

An alternative suggestion is that the settlements residue be immediately returned to spot market participants. It is proposed that the settlements residue would be distributed to certain retailers and/or generators in proportion to the extent and nature of their participation in the spot market at the time that the residue was accumulated.

The Commission understands that the basis for this proposal is that giving the residue to market participants will allow them to commercially trade the residue in the market. It is claimed that this is a more viable option than delivering the residue to NSPs who are non-commercial players, and will eliminate the need to establish trading in IRHs.

However, it is not obvious to the Commission why generators or retailers have a legitimate claim to what is essentially a transport related revenue. Nor is it apparent where the commercial incentive for generators and retailers to pass the settlements residue on to end use consumers would come from. Returning the residue to market participants may be a simple option, but given the above concerns over incentives it is doubtful whether this option meets the efficiency or transparency objective.

In addition, the assignment of the residue to generators or retailers raises a number of equity issues that would need to be resolved. Furthermore, is not clear how the settlements residues arising from marginal loss factors, in this and the following option, can be similarly distributed without losing, or at least diluting, locational signals.

Use the settlements residue to relieve network constraints

The accumulation of a residue provides a signal that it may be economically viable to augment the interconnector and hence remove constraint payments. Hence it has been suggested that where a settlements residue is accumulated it be used to relieve network constraints. However, this option raises a number of issues, such as who becomes the owner of the interconnector and is thus entitled to the remaining and future settlements residue, as well as regulated income. Moreover, augmentation of the interconnected network may not be the optimal solution.

Commission decision

In summary, the Commission considers that the proposal to distribute the settlements residue to end use consumers via NSPs reducing network charges is the most transparent, equitable and efficient distribution of the residue. The applicants have indicated that this is the approach which they will be adopting.

8.10 Ancillary services

Ancillary services are services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of an acceptable quality. The Code provisions in relation to ancillary services are set out in clause 3.13.

Issues for the Commission

The central purchasing of ancillary services, and the requirement that NEMMCO set minimum standards which are to be dealt with in Code participants' connection agreements for technical performance, might be held to be:

- exclusionary provisions in that participants agree not to obtain network services from persons unless they comply with the requirement to acquire such ancillary services;
- exclusive dealing provisions, as participants trade on condition that NEMMCO will only acquire ancillary services from market participants;
- third line forcing provisions (which is a form of exclusive dealing), in that NEMMCO is supplying services to NSPs on condition that they obtain ancillary services from Code participants; or
- provisions substantially lessening competition, if the requirement creates a barrier to entry to or lessens competition in the market.

What the interested parties say

EnergyAustralia, the Victorian DBs, Hazelwood Power, TransGrid and the EUG all recommend that, where possible, the development of a competitive market for ancillary services should be encouraged. Most of these submissions argue that where these ancillary services cannot be sourced competitively, regulated price setting mechanisms will need to be adopted.

Yallourn Energy claims that the provisions in the Code relating to ancillary services are inadequate. Yallourn Energy objects to the reliance on providing ancillary services through closed bilateral negotiations, since information regarding such contracts is withheld from other participants yet it is well established that the availability of full information is a prerequisite for efficient market outcomes.

Delta Electricity considers that the arrangements for the provision of ancillary services specified in the Code are acceptable.

What the applicants say

The applicants state that maintaining the quality of electricity to all network users is important. They claim the resultant public benefit of such quality of supply through the requirement that network users be forced to provide ancillary services through connection agreements will outweigh any potential anti-competitive detriment arising from such a restriction because of the common good nature of ancillary services. Accordingly, the applicants argue that without this requirement there would be an inherent weakness in the market with an under-provision of such ancillary services, as some users would not bear the full costs of their actions.

Issues arising from the draft determination

At the pre-decision conference and in subsequent submissions,[60] there was general support for an early review of the provisions relating to ancillary services with the objective of introducing market-based arrangements for the delivery of such services. The majority of these submissions support the Commission's condition that NEMMCO report on the review findings to NECA within one year of the market commencing. Several submissions cited the capacity of dispatch software to accommodate the trading of ancillary services.

There is general support for the unbundling of ancillary services as separate products outside of the pricing arrangements for network services or pool fees. Submissions from several generators[61] indicate that commercial arrangements for the supply of ancillary services would be a more suitable means of supporting technical requirements for network and system security. They also state that a corollary of an ancillary services market would be revision of the Code to remove a perceived bias favouring NEMMCO contracts for ancillary services, to remove ancillary services requirements from connection agreements and to revise existing technical standards for generators.

Some submissions advise caution in the development of an ancillary services market. Hazelwood Power states that a two year timeframe for the review would be more appropriate given that the need for substantial Code changes to the technical standards for generators and to ancillary services arrangements. Similarly, Pacific Power proposes that current arrangements for ancillary services remain in place until the review is completed, to ensure the capacity of the dispatch software and the commercial viability of new arrangements. Dr Hugh Outhred, commenting on the NEM 1 Ancillary Services Project, questions whether one year would allow sufficient time to achieve a balanced outcome which accounts for distributed resources and demand side perspectives.

Commission considerations

The acquisition of ancillary services by NEMMCO is based on the possible failure of the market to provide sufficient ancillary services. Safe, stable and reliable management of the market demands that ancillary services be available. The whole market benefits from the provision of such services which maintain the quality of electricity supply. However, without the ancillary service requirements of the Code there would be an under provision of ancillary services as some users would not bear the full costs of providing them, preferring instead to 'free ride'.

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[60] EUG; Business Council of Australia; CitiPower; Eastern Energy; Solaris; SMHEA; Macquarie Generation; Yallourn Energy.

[61] Delta Electricity; EME; Hazelwood Power; Loy Yang; Optima Energy; Incumbent Victorian generators.

With shared benefits arising from ancillary services a centralised buying entity, such as NEMMCO, may be required to perform the function. However, the Commission considers that only some ancillary services possess the characteristics which warrant their provision on a centralised basis. The development of a market in the provision and consumption of ancillary services is possible for those services that can be attributed to specific users. This is foreshadowed in the Code by the requirement for NEMMCO to conduct an investigation and report within two years of market commencement on the possible development of market based arrangements for the provision of these services.

The development of a market in the provision of ancillary services is desirable to generate the right market signals to achieve productive and dynamic efficiency with respect to investment decisions. However, a competitive market will be dependent on there being a sufficient number of eligible providers. Although the ability to identify cost causality varies with the specific ancillary service, the extent to which this can be done economically should be investigated. Market signals are enhanced if ancillary services are recovered from the parties responsible for creating the need to the greatest extent possible.

The Commission has been informed that the Code's ancillary service provisions will be substantially amended before the start of the national market. The Commission understands that the NEM 1 jurisdictions are pursuing changes to their Codes to facilitate the development of an ancillary services market and it is anticipated that ancillary services contracts will be put in place under the NEM 1 arrangements. The Commission also understands that these contracts will be dispatched under the NEM.

The Commission has received an outline of the ancillary services arrangements that are to operate at the inception of the NEM. It appears that these arrangements support the market based provision of ancillary services, where possible. Such an approach is favoured by the Commission.

In view of the overall support at the pre-decision conference and in subsequent submissions for an early review of the existing ancillary services provisions, the Commission confirms the condition of authorisation.

At the same time, the Commission notes the reservations expressed by a number of submissions regarding the need for extensive Code changes in relation to ancillary services, system security contracts, connection agreements, demand side issues and technical derogations. The Commission believes it will be critical that these issues are adequately addressed by the review and subsequent decisions, to ensure the successful implementation of market arrangements for ancillary services that are open to all Code participants.

Condition of authorisation

C8.10 Clause 3.13.1(c) of the Code must be amended by substituting 'one year' for 'two years' in that clause.

8.11 Market information

The Code regulates the information which must be made available by Code participants to the public, other Code participants, NEMMCO and NECA. The applicants state the information disclosure requirements defined in clause 3.15, Chapters 4 and 5, and clause 8.6 of the Code have been designed based on the following principles:

- information is only withheld if it is 'confidential information' (such as commercially sensitive information);
- where necessary, 'confidential information' is aggregated for publication;
- information disclosure supports the pursuit of market efficiency and is consistent with 'light handed' regulation;
- information disclosure removes an advantage that most large market participants would otherwise enjoy over small market participants and increases the prospects of attracting new entrants to the market; and
- information disclosure empowers market participants to monitor market behaviour and thereby should assist in deterring gaming by market participants.

8.11.1 Information requirements

The Code requires NEMMCO to impose extensive information and data collection obligations on Code participants. NEMMCO must in turn provide this information in various forms to market participants according to the timetable.[62] NEMMCO must also make available to market participants on request any information concerning the operation of the market not defined by NECA or the Code as confidential or commercially sensitive, and may charge a fee reflecting the cost of providing such information.[63]

Issues for the Commission

The compilation and release of information imposes costs on participants which may deter entry to the market. The information collected and published by NEMMCO could potentially be used by market participants to engage in anti-competitive conduct, and this needs to be weighed against the potential market efficiencies arising from NEMMCO collecting and disseminating information. Such anti-competitive conduct may constitute:

- contracts, arrangements or understandings that have the purpose or effect (or likely effect) of substantially lessening competition in a market; or
- contracts, arrangements or understandings that would have the purpose, effect or likely effect of fixing, controlling or maintaining prices,

in contravention of s. 45 of the TPA.

What the applicants say

The applicants' argue that the disclosure of information from generators and other market participants is necessary to enable NEMMCO to make timely and informed decisions about dispatch, reserve, load shedding and other system security and operational matters.

Moreover, they state there is public benefit in ensuring that such information is available to participants and other interested parties in sufficient detail and good time to enable efficient

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62 The timetable is to be published by NEMMCO under clause 3.4.3 for the operation of the spot market and the provision of market information.

63 Issues regarding confidentiality are discussed in section 13.4.

market responses. The applicants argue that an informed market will be able to function effectively and efficiently in order to clear short term constraints in ways best calculated to serve customer and end user interests.

Commission considerations

The requirement that Code participants provide information to NEMMCO may be costly, particularly for smaller participants, and hence could potentially be a barrier to entry. However, there are significant public benefits in having participants provide this information on a timely basis to NEMMCO, as it helps to maintain the supply of electricity and ensures that the network is operated in a secure and efficient manner.

Western Power, in its Technical Review of the Code, acknowledges the large volume of information provided may be overwhelming for smaller participants. In regard to participants providing this information to NEMMCO, Western Power suggests it may be viewed as a disadvantage to new entrants because of the set up cost. However, Western Power notes that it is recognised that the ongoing costs should be small, and it is likely that participants would need to produce this type of information for use in their businesses anyway.

The information provided to NEMMCO can be classed as marketable information. However, NEMMCO has no commercial interest in market outcomes and the Code does not provide for NEMMCO to commercially trade this information. Given that certain information is considered necessary for the efficient operation of the market there is a distinct public benefit in having a single entity obtain and disseminate information. If this was not the case there is a possibility that not all participants may have access to the same information and this may competitively disadvantage smaller participants.

Market information is to be provided by NEMMCO through an electronic communications system. Western Power notes that there is no mention of a back up system or facility. It therefore suggests pursuant to clause 3.15.2(a), that a back-up system should be defined in the event the electronic communications system fails or is unable to be accessed by some Code participants due to congestion problems.

Given the importance of market information for the effective functioning of the NEM the Commission has imposed conditions of authorisation which addresses the need for a backup communications system.

The Commission's primary concern is that the volume and detail of information may be used in an anti-competitive manner by market participants. These concerns with regard to specific information disclosure requirements are discussed in the following sections.

8.11.2 Projected assessment of systems adequacy

Forecast information about plant availability and maintenance intentions of generators and network operators are disclosed in the projected assessment of systems adequacy (PASA) (clause 3.7). The PASA is designed as a comprehensive program of information collection, analysis and disclosure of medium term and short term power system security prospects so that market participants are properly informed to enable them to make decisions about supply, demand, and outages of transmission networks. NEMMCO will manage the process of information collection, analysis and disclosure of PASA.

Issues for the Commission

The Commission must assess whether the system security and efficiency benefits of disclosing PASA information outweigh the potential for this information to be used in an anti-competitive manner. Such anti-competitive behaviour may contravene the TPA in a similar manner to that outlined in section 8.11.1. Further, PASA could be used to manipulate spot market prices for commercial advantage by some market participants, behaviour that, while not in contravention of the TPA, could nevertheless significantly detract from the potential public benefits of the market arrangements.

What the interested parties say

TransGrid, Environment Australia, the Tasmanian Government and Macquarie Generation note PASA's importance in allowing decentralised decision making and maintaining system security.

The IC supports the disclosure of PASA information as proposed in the Code because it increases market transparency and promotes efficiency by ensuring that both sellers and buyers have access to the same information.

The EUG and Boral Energy are concerned about the potential to misuse PASA information for anti-competitive ends. However, the EUG notes limiting the availability of this information may only intensify these problems.

Mr Chek Ling states that in his view PASA is 'tedious and resource expansive' and it remains to be seen whether it will achieve the outcome currently achieved in terms of minimising the cost of production over the medium term. He suggests that if the Commission feels too much information is 'given away' it might be wise for system operation to retain its central function, but with clear rules and audit trails so that integrity is always assured.

What the applicants say

The applicants note there has been some contention that competition in the market could be lessened by the collection and publication of PASA information because this information could potentially be used to manipulate spot prices.

They argue, however, such a lessening of competition is unlikely to occur and to the extent that it may, any such effect will be clearly outweighed by the benefits of the widest possible dissemination of PASA.

Their arguments in support of PASA are summarised below.

- Maintenance outages were previously centrally co-ordinated. The PASA provides a market based approach to the alternative of central co-ordination. In order to achieve this it is vital that sufficient data is made available to all participants on which to base these potentially critical commercial and operational decisions.

- The risk of any participant using PASA information to manipulate market outcomes is remote and limited. Participants can only manipulate market outcomes if they have market power. If PASA was restricted there is a distinct risk that it would be available, albeit in a less complete and less systematic form, to a few only. In that case there is a risk of information asymmetry leading to market power and accordingly the possible manipulation of market outcomes becomes a real concern.

In addition, if this information is not made available generators may be forced to adopt costly strategies such as:

- carrying unnecessary spinning reserve which, in turn, will decrease the efficiency of operation of the total system and increase overall costs;
- passing on to end use consumers the costs of increased risk; and
- putting in place insurance schemes, again at industry and end use consumer expense.

■ The ability to uncover abuses of market power will depend on access to sufficient data from the spot market and the financial market. It is submitted that the balance of the argument is to publish as much data about the market as possible, in order to increase market efficiency and allow market participants to monitor each other.

Commission considerations

The Commission's primary concern is that PASA may provide market participants with information enabling them to manipulate price outcomes through strategic scheduling of their own generation plant. Experience from the Victorian and England/Wales markets indicates that spot prices can be increased by the unavailability of large generation units. This gives rise to concern that providing each generator with data on the availability of plants on the system could facilitate anti-competitive behaviour. For example, a large generator could declare one of four units unavailable, having calculated that the increase in the spot price would more than compensate for having spot market income from three units rather than four.

PASA information is released on a regional basis, hence the number of generators in a particular region will also influence the extent PASA information can be used to manipulate the market.

The ability of market participants to use the PASA information to manipulate market outcomes will depend upon the extent of contractual obligations and exposure to the spot price, at least in the short term. If the spot price exposure is quite low then there is commensurately reduced scope for generators to benefit from high spot prices. This is currently the case due partly to vesting contracts, and may continue to be the case in the future if the bulk of trading is through bilateral contracting. However, if spot price exposure was to increase over time spot prices could be expected to influence contract prices, so that generators may benefit if they are able to maintain overall higher spot prices.

The Commission notes that restricting PASA may introduce perverse incentives where participants deliberately provide misleading information to gain information on scheduled outages and demand forecasts. This kind of behaviour devalues the PASA process and puts system security at risk. Without this information, participants would be less able to accurately assess market opportunities and would run the risk of being directed to return to service (which cannot always be done quickly) or not commence planned maintenance (which may entail substantial cost). This view was endorsed by Western Power.

Overall, the public benefits arising from the provision of PASA with respect to system security and the need for PASA to allow decentralised decision making regarding the scheduling of outages would appear to outweigh the possible anti-competitive detriment arising from the information being used to manipulate market outcomes.

8.11.3 Price and quantity bid disclosure and forecast sensitivities

Clause 3.15.4 sets out the spot market information that will be made available and the timing of its publication. Each day NEMMCO must determine the pre-dispatch schedule for each trading interval on the basis of dispatch bids and offers (clause 3.8.20), and include the details set out in clause 3.15.4(f). NEMMCO is to publish each day's forecast sensitivities, although the degree of sensitivity is not explicitly stated (clause 3.15.4(h)).

Details of each market participant's final dispatch offers and dispatch bids received, actual availabilities of generating units and scheduled load for the previous trading day are to be published including:

- the number and times at which any rebids were made;
- identification of the market participant submitting the dispatch bid or the dispatch offer;
- the dispatch bid or offer prices;
- the quantities for each trading interval; and
- identification of trading intervals for which the plant was specified as being inflexible (clause 3.15.4(p)).

Each day NEMMCO must also publish details of the dispatched generation or dispatched load for each scheduled generating unit and scheduled load in each trading interval for the previous trading day (clause 3.15.4(q)). The exact timing will not be known until the market timetable is provided by NEMMCO.

Issue for the Commission

The Commission must assess whether the system security and efficiency benefits of disclosing market information outweigh the potential for this information to be used in an anti-competitive manner. Such anti-competitive behaviour may contravene the TPA in a similar manner to that outlined in section 8.11.1. Further, the market information could be used to manipulate spot market prices for commercial advantage by some market participants, behaviour that, while not in contravention of the TPA, could nevertheless significantly detract from the potential public benefits of the market arrangements.

What the interested parties say

In their submissions to the Commission, the EUG, IC, Hazelwood Power, SMHEA, TransGrid, Ecogen Energy, Integral Energy and Yallourn Energy all support the arguments for the release of bid data for one or more of the reasons presented by the applicants.

Integral Energy and Yallourn Energy argue that if market information and, in particular, price/quantity bid data is not released, the potential for gaming is increased, and according to Hazelwood Power, without the information, market participants will be unable to monitor each other's behaviour.

The Victorian DBs, energyAustralia and SMHEA both say that not releasing this information would cause information asymmetries and increase market risk.

TransGrid does not deny the possibility that the release of bid prices and quantities shortly after use in a repetitively bid market could lead to tacit collusion. However, it states there are substantial disadvantages in not releasing this data.

Delta Electricity is the only interested party that supports the principle of maintaining confidentiality of generator bid data. Delta Electricity argues the release of bid data will stifle business efficiency drivers, reduce innovation and decrease competition. It adds any information disclosure will indeed aid implicit collusion.

Australian Paper says it is concerned that if generators know the bid strategies of their competitors, then ultimately prices will rise. It notes that in a competitive world competitors only know the results of their competitor's strategies, and so bidding strategies should remain confidential.

The BCA states that, depending on the extent of disclosure and the number of active participants in the spot market, the extent of information disclosure needs to be kept under strict observation and may need to be controlled/restricted/delayed to minimise the chance for tacit collusion. A one week delay in releasing bid information is proposed by energyAustralia; information would be released outside the bidding cycle yet would still assist market customers.

What the applicants say

The applicants acknowledge the Commission's reservations regarding the extent of release of market information in their submission. However, they provide material in support of their argument regarding information disclosure, including a study by St. Clements Services[64] which examines the UK experience in the context of the need for information to aid in market efficiency, and evidence from the US on the importance of information disclosure for the detection of gaming.

The arguments forwarded by the applicants in favour of information disclosure are summarised as follows:

- the disclosure and publication arrangements in the NEM are based on an assessment of experience gained in overseas electricity markets;
- market efficiency requires a high level of information, and any asymmetry of data provision between contracting parties is likely to advantage one side against the other. For example:
  - new entrants will be deterred if they are unable to assess the risks associated with market entry; and
  - in a market where customers are primarily price takers it is important that they understand the way prices are set and analyse the drivers of spot market outcomes;
- if denied access to information after dispatch, retailers will be unable to construct the bid price function and therefore will not be able to model the relationship between load and price, resulting in retailers effectively operating blindly in the market.

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64 Applicants submission, Schedule 14.

The applicants submit that most existing industry participants are already aware of the current long run and short run generation costs of different technologies. In fact ECC Consultants [65] for the NGMC suggest that if such data is not disclosed it can be fairly accurately estimated given the final offer/re-offer and bid/rebid data, but only the larger participants will have the resources to develop such estimates. Hence, it is suggested that this knowledge already provides an opportunity for tacit collusion whether or not bids are published. [66]

If this is the case, then according to the applicants the publication of information is one of the major checks available to retailers and end use consumers to detect potentially anti-competitive behaviour. If anti-competitive behaviour is detected this allows interested parties to:

- impose peer pressure to desist;
- report to regulatory authorities to take any appropriate action;
- impose wider public pressure to desist; and
- retaliate, perhaps by replicating the behaviour and eroding the advantage gained.

Therefore, according to the applicants the release of information is critical to auditability and transparency, and the overriding benefit is to have a well informed market where no individual player can extract benefits at the expense of others because of information asymmetry.

Commission considerations

There are powerful theoretical arguments for limiting the degree of information sharing or dissemination between firms in a market such as electricity, as outlined in a paper prepared by Harbord et al (1997).[67] In a repeated 'game' all competitors can benefit through tacit collusion. In fact, economic theory clarifies the conditions under which successful collusion is likely to occur, namely:

- more frequent market interaction tends to facilitate collusion;
- information concerning past strategies such as price and quantity is more effective in sustaining higher degrees of collusion than information concerning market conditions such as demand; and
- aggregate information is less valuable than disaggregated data for monitoring rival strategies and hence sustaining collusive outcomes.

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65 ECC Consultants, Brief (a) *Bidding and Dispatch Proposals*, December 1995.

66 Tacit collusion may be characterised as behaviour which, whilst not overtly organised, can have an effect on prices (higher than they would be under competitive outcomes) similar to other forms of collusive behaviour, such as price fixing. The success of a tacitly collusive arrangement between competitors relies on information about each participant to the collusion being available to all participants, so that individual behaviour can be monitored.

67 *Competition Policy and Information Dissemination in the National Electricity Market. The Effects of Pool Information Disclosure*, paper by David Harbord and Associates, European Economic Consultants on behalf of Macquarie Generation, Delta Electricity, Integral Energy and EnergyAustralia, 1997.

The first of these three conditions characterises the design of the electricity market. The second and third conditions are embedded in the market rules in that market participants will be provided with information regarding the bidding behaviour of their competitors.

In the NEM individual price and quantity bids will be disclosed to market participants, and the potential for this information to be used in an anti-competitive manner cannot be dismissed. In simple terms the proposed arrangements provide details of individual dispatch bids and offers, thus disclosing to competing generators any divergence from a tacitly agreed-to bidding strategy, enabling conforming generators to punish non-conforming generators.

In addition, participants are given access to sensitivity data and the methodology and standing data inputs into forecasts. This is powerful knowledge when coupled with the rebidding provisions[68] as it can be used by generators to withhold or shift capacity in order to increase the spot price. The key to success of a capacity withholding bidding strategy, in obtaining higher prices, is that a larger generator knows that a significant proportion of its capacity will be called upon regardless of the price of its bids. Currently, the New South Wales and Victorian markets are characterised by excess capacity — as this declines and if the demand side remains unresponsive, generators will know with more and more certainty what fraction of their capacity will be required to serve the market.

It has been argued that the market may operate more efficiently if information was restricted, or released after a period of time or not at all. However, the Commission considers that this is likely to be an ineffective solution.

Firstly, if forecasts were not provided by NEMMCO a well functioning STFM would provide a similar price revelation mechanism. In addition it would be in the interests of the main players to ensure, through co-operation, that such a function was available.

Secondly, the Commission is of the view that to delay the release of price and quantity bid information would be of little value. Participants have indicated that the information of most value to them is the forecast sensitivities, and that this data can be used in much the same way as the price quantity bid information.

Thirdly, the Commission has been informed by interested parties that the larger players have the resources to derive the information they require, so that restricting information disclosure would only disadvantage smaller players.

Finally, the applicants state the immediate dissemination of at least some information may serve the purpose of economic efficiency, and may act to prevent rather than encourage collusion. The applicants and interested parties have stated that disclosure will permit monitoring of anti-competitive behaviour allowing pressure to be put on those engaging in such behaviour to desist. The Commission, however, is not entirely convinced by such an argument. To ask generators not to serve their shareholders and exploit these market rules to earn higher profits is contrary to the purpose of privatising and corporatising firms (i.e. giving firms the incentive to maximise profits).

[68] Rebidding is dealt with in section 8.5.

Although the Commission is concerned about information disclosure, this fundamentally indicates an underlying concern with market structure and lack of demand side response.

The report by ABARE on *Strategic Behaviour in the National Electricity Market* suggests that the current structure of the NEM is characterised by a significant degree of market concentration particularly in South Australia and New South Wales. Large generation portfolios may be in a position to adopt non-competitive bidding behaviour particularly in high demand periods. Such strategic behaviour, due to the linked nature of the NEM, has the potential to lead to significant increases in electricity prices such that all generators will benefit from strategic behaviour from the major players. Regulation can provide a check on the exercise of market power. However, this option is not without costs. Alternatively, further structural reform may remove the need for regulatory intervention.[69]

The public benefits of reform may be reduced or negated if sufficient action is not taken by the respective jurisdictions — in particular New South Wales and South Australia — in order to encourage the development of a more competitive market structure and, in the longer term, demand side elasticity.

The other aspect that must be developed in conjunction with action on structure is the need to develop demand side flexibility. The larger the demand uncertainty faced by generators relative to capacity, the more likely it is that all generators will have an incentive to bid aggressively because they face the prospect of being left out of the market during that trading period. However, the responsiveness of the demand side is likely to increase in the longer term.

8.11.4 Market monitoring

Due to concerns with anti-competitive behaviour the Commission believes that there is a need for an entity to monitor market behaviour and Code compliance.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.13 NEMMCO's functions in clause 1.6.3 must include monitoring trading activity. NEMMCO must have responsibility for reviewing each day's trading to ensure that all transactions are done in accordance with the Code.

Discussion at the pre-decision conference reflected concerns that NEMMCO may not be the most appropriate organisation to undertake a monitoring role. Whilst there was broad support for monitoring of market behaviour, over and above the monitoring of Code compliance, it was seen as a more appropriate role for the enforcement agencies, either NECA or the Commission itself.

Support for the market monitoring to be undertaken but reservations about whether NEMMCO is the most appropriate body to undertake such a role is also presented in submissions from the applicants, BCA, EUG, EME, Hazelwood Power and SMHEA.

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[69] The issue of market structure and its importance to competitive outcomes is discussed in section 5. Also see: Melanie, J., and Brennan, D., *National Electricity Market: Strategic Behaviour*, Australian Commodities, Volume 4, Number 1, March Quarter 1997.

TransGrid supported the need for a market monitoring role and suggested an automated system similar to that used by the Australian Securities Commission would be appropriate.

Commission considerations

The Commission notes that the Code assigns NECA the responsibility to monitor and report on compliance with the Code and the adequacy of the Code. Under the existing provisions any behaviour which is within the rules but which may be anti-competitive will only be picked up by NECA reporting on the adequacy of the rules. Whilst Code compliance is obviously an important issue the Commission feels that monitoring of the market should also involve an assessment of behaviour within the competitive market. The Commission believes that it is important that participant behaviour is subject to an active monitoring process. This view was supported by participants at the pre-decision conference.

Broadly, this monitoring process should aim to determine whether market participant behaviour highlights areas in which the existing rules need to be changed, or whether there is evidence of any market participant acting in an anti-competitive manner. Any concerns identified should be considered by the body with responsibility for market monitoring and also may also be considered by the Commission, which may take action under the TPA. The Commission notes the concerns put forward at the pre-decision conference regarding the appropriate body to undertake a market monitoring role, and also the position put forward by the applicants in their submission to the Commission in response to the draft determinations.

The applicants have submitted a market monitoring model which separates the functions of enforcement, investigation and administration and allocates responsibility for these tasks to appropriate bodies. The enforcement role remains with the Commission in respect of breaches of the TPA, and with NECA regarding Code compliance. The applicants propose that NECA would act as the investigation agent, setting out the data collection and analysis requirements and setting the parameters to be used in undertaking investigations. The administrative agent would be responsible for performing the data collection and processing as specified by the investigation agent, and the applicants propose that NEMMCO would act as the administrative agent. Detail of the arrangements and the responsibilities of each agent would be set out in protocols developed between the bodies and also in the Memorandum of Understanding currently being developed by the Commission and NECA.

The arrangements proposed by the applicants would be acceptable to the Commission, depending on the parameters set out for investigations. However, given the concerns of the Commission all market participants, particularly end use consumers who are price takers and who currently have limited demand side flexibility, are strongly urged to take an active monitoring role of market behaviour on the supply side. Again, concerns may be raised initially with NECA, and if sufficient evidence is available the Commission may take action under the TPA.

8.11.5 Information disclosure to the public

According to clause 3.15.1 NEMMCO must make available to market participants, on request, any information concerning the operation of the market not defined by NECA or the Code as confidential or commercially sensitive. NEMMCO may charge a fee reflecting the cost of providing such information.

Clause 3.15.9 also requires NEMMCO to publish, on a daily basis, information for the previous trading day. Clause 3.15.9(b) says that all market information that NEMMCO is required to publish in accordance with the Code shall also be made available by NEMMCO to persons other than Code participants within a reasonable time on a fee basis.

Issues for the Commission

The issues which arise are that the actual information to be published, the determination of the fee for service, and the timeliness of the provision of the information to non-participants may be anti-competitive. For example, non-Code participants such as financial institutions need real time information in order to effectively trade financial instruments. Not having the right to the same information as Code participants could therefore limit the development of alternative financial instruments.

What the interested parties say

The Partnership Group recommends the Code be redrafted so that NEM spot price information will be public information made available by NEMMCO instantly, completely and without discrimination, to all interested parties.

Sinclair Knight Merz argues open information should be provided to prospective participants and interested third parties (environmental groups, etc.) as well as existing participants. It says if such information is not readily available the possession of information becomes an entry hurdle for new participants.

Integral Energy believes that for any market to function efficiently market information should be made available to participants and other interested members of the public.

EWN Publishing contends maximum information access and diffusion will maximise the benefits associated with the Code. More importantly it argues the rights of market participants and the public to access information should be the same.

The EUG believes bodies representing market participants and potential new entrants should have access to the information provided in clause 3.15.9 without charge as this will help to overcome a market failure and improve entry conditions at a relatively small cost to NEMMCO and NECA.

What the applicants say

The applicants state there is public benefit in ensuring that information is available to participants and other interested parties in sufficient detail and good time to enable efficient market responses. They state an informed market will be able to function effectively and efficiently in clearing short term constraints in ways best calculated to serve customer and end user interests.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C8.12 Clause 3.15.9(c) must allow all interested parties instantaneous undifferentiated access to spot prices and related market information provided by NEMMCO via its electronic communications system.

The applicants sought clarification as to what was meant by instantaneous undifferentiated access.

At the pre-decision conference the applicants indicated their intention to allow non-Code participants access to the NEMNET system, for a fee commensurate with the cost of providing the service. They stated that the cost of such arrangements may be as much as $20 000. Further, the applicants indicated that they intend to place information on their web site where it would be available to any interested person.

TransGrid, in its submission, suggested that allowing non-Code participants access via the NEMMCO electronic communications system could result in congestion problems, and while supporting the thrust of the condition imposed, feels that NEMMCO should be allowed some discretion in how it provides information.

Commission considerations

There are a number of parties who, for various reasons, will have an interest in spot market outcomes and the information available to participants — even though they themselves are not participants in the wholesale market. For example, financial institutions need access to forecast and real time information in order to assess their exposure. However, it is not clear from the Code that non-participants who wish to receive all published information at the same time as participants can do so.

Clause 3.15.9 regarding public information is deficient in two respects. Firstly, the clause obliges NEMMCO to publish market information on a daily basis only and for the previous trading day. Secondly, NEMMCO need only make this information available 'within the reasonable time requested by the person' seeking the information.

This clause implies that NEMMCO has some form of proprietary control over the information. If this is the case then one of the fundamental design principles for open access to the information is not achieved. Interested parties who want it should have access to the same information that Code participants have access to, and the fee for providing this service should be cost reflective. The Commission notes that the applicants have agreed to revise the Code in the light of the Commissions concerns.

8.11.6 Overall assessment

A major concern in the proposed arrangements is the scope for strategic behaviour and/or tacit collusion between competitor generators in the market, and the information flows that may facilitate this.

The Commission has previously signalled its concerns in this area, with respect to the interim authorisation of the New South Wales State Electricity Market Code, and by raising this issue in the paper *Comments and Issues Arising*. However, market participants in New South Wales and Victoria in relation to the NEM1 and intending participants in the NEM have argued to the Commission that market information must not be restricted.

In general terms there are difficulties in assessing the balance between the possible detriment to the market and end use consumers, partly due to a need for more information and partly due to the fact that any action to restrict information, previously easily available, will impose costs on the market.

Each of the information disclosure issues discussed must be considered together with other issues, including the key factor of the ability of competitors to revise their bids into the market, the number and size of participants in the market and the extent of demand flexibility. The combination of forecast information, data on competitors, bidding strategies, and knowledge of competitors' intentions provides generators in the market with an opportunity to adjust their behaviour to ensure profit maximisation. This will impact upon the efficiency of the market and as such reduce the level of public benefit that may be derived from the introduction of competition to the electricity generation and retail industries. This will ultimately become a cost borne by consumers.

Given the discussion outlined in this section, it is acknowledged that there are efficiency benefits from the release of market information. However, these need to be considered against the potential for this information to be used to manipulate spot market outcomes. As discussed, market manipulation is difficult to detect and the UK experience highlights the significant public detriment that can arise from such behaviour.

The Commission finds that:

- There is public benefit arising from the provision of PASA with respect to system security and the need for PASA to allow decentralised decision making regarding the scheduling of outages which outweigh the possible anti-competitive detriments arising from the information being used to manipulate market outcomes,

- The nature and importance of information to the efficient operation of the market means that there is a distinct public benefit in having a single entity obtain and disseminate information.

- With regard to the disclosure of price and quantity data and forecast sensitivity, the Commission is of the view that there is significant potential for anti-competitive detriment to arise from not allowing this information to be released. This is due to an underlying concern with the structure of the market and lack of demand side flexibility. On balance however, for the reasons outlined, the Commission will permit this information to be disclosed on condition that provision is made for daily monitoring of the market. The Commission has imposed a condition of authorisation in regard to market monitoring (see section 8.5, and condition of authorisation C8.4).

- Given concerns with information disclosure the Commission strongly urges market participants to take an active monitoring role in the market, and raise any concerns initially with NECA. If sufficient evidence of anti-competitive conduct is available the Commission may take action under the TPA.

- Provision for access to market information by non-market participants is unclear. However, the Commission has been assured by the applicants that interested parties have been provided with access to information. The intention of the Code is unclear as evidenced by the number of interested parties who raised the issue, and will need clarification.

Conditions of authorisation

C8.11 Clause 3.15.2(a) must be amended to provide for a back-up system to be used in the event that the electronic communications system fails or is unable to be accessed by some Code participants.

C8.12 Clause 3.15.9(b) must be amended to provide that:

(a) any person can access the information available to market participants, other than confidential information, provided by NEMMCO via its electronic communications system; and

(b) any charge by NEMMCO to persons for provision of access to this information must be on a cost reflective basis.

C8.13 The Code must be amended to provide that NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of clause 3.15 of the Code. The review must consider the adequacy and appropriateness of these provisions, and any alternative provisions which might be added or substituted therefore, in meeting and facilitating the Code objectives. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

8.12 Market audit

The Code requires NEMMCO to arrange for a market audit to be performed on an annual basis with the objectives of the market audit including but not being limited to:

- auditing the calculations and allocations performed by the metering and settlements systems;
- auditing the billing and information systems;
- auditing the scheduling and dispatch process;
- review of NEMMCO procedures and compliance with the Code.

Following consideration by NEMMCO the market audit report must be made available by NEMMCO to market participants on request.

Issues for the Commission

The Commission considers that the public benefit arising from the NEM will be enhanced by audit provisions that will increase market transparency and confidence of market participants.

Commission considerations

The Commission has concerns regarding who should carry out the market audit and the public availability of any auditors' reports. In order to increase market transparency and maintain market participant confidence, the market audit should be carried out by an independent entity and carry the signatures of both the auditors and NEMMCO in a manner similar to a company annual report. It is not obvious why NEMMCO should wish to consider the report prior to its public release because, to do so may cause some Code participants and interested parties to lose confidence in the market.

Condition of authorisation

C8.14 Clause 3.15.10 of the Code must be amended to provide that:

(a) the market audit must be conducted by an entity that is independent of NEMMCO and the market participants;

(b) NEMMCO must either approve and endorse the market audit report and any recommendations therein by noting such approval and endorsement on the report or prepare a separate report dealing with each of the matters within the market audit report that NEMMCO does not approve or endorse; and

(c) the market audit report and any separate report by NEMMCO are to be provided to market participants and are to be made available to the public.

9. Power system security

Electricity is a good whose supply and transportation through the power system requires continual balancing to ensure safety, security and quality of supply. Chapter 4 of the Code provides technical specifications and procedures for achieving and maintaining a secure power system. The Code also sets out the responsibilities of NEMMCO and Code participants, and the conditions under which NEMMCO can intervene in the market and issue directions to Code participants.

This section is divided into two parts, section 9.1 examines the Code's system security requirements, drawing heavily on technical issues presented to the Commission by its consultants, Western Power Corporation and Colin Taylor and Associates. Section 9.2 examines the provisions in the Code for NEMMCO intervention in order to maintain reliability of supply.

9.1 Power system security

Chapter 4 of the Code sets out technical requirements to ensure the safe and reliable supply of electricity. Code participants are also required to meet certain technical and procedural obligations to assist NEMMCO fulfil its responsibilities and obligations with regard to power system security.

Issues for the Commission

The Commission must consider whether the technical requirements and obligations placed on Code participants contribute to the anti-competitive detriments arising from the Code's arrangements by deterring entry or placing unnecessary burdens on those already operating in the market without generating offsetting public benefits from maintaining secure and well functioning electricity supply arrangements.

What the interested parties say

SMHEA argues that system security standards should be in line with customers' needs. SMHEA also states that 'ideally, system security should be managed through a competitive ancillary services market and user pays charging of ancillary services'.

Boral Energy state that Chapter 4 needs to be reviewed regularly.

What the applicants say

In supporting the Code's power system requirements, the applicants state that:

> *... the operation of an integrated power system is complex and therefore it is essential that the accountabilities and responsibilities for maintaining the system quality of supply attributes of frequency and voltage to all users and the integrity of equipment comprising the power system are clearly defined.*

The applicants argue that the Code's prescriptiveness for the responsibilities and obligations of Code participants helps to reduce ambiguity and makes the requirements for entry clearer and less risky to possible new entrants. Moreover, the applicants argue that it is in the public interest for the power system to meet such quality of supply and technical safety standards. In meeting this objective, the applicants state that the technical and operational requirements in Chapter 4 of the Code are consistent with good electricity industry practice and applicable Australian Standards.

The consultant's view

The Western Power review concludes that Chapter 4 of the Code:

- does not impose any unnecessary requirements on those seeking entry;
- imposes requirements which are consistent with reasonable industry practice;
- imposes a reasonable degree of responsibility on all NSPs;
- does not advantage or disadvantage current NSPs; and
- will not impede future development of the market.

Western Power does, however, make a number of comments and suggestions about areas of Chapter 4 that could be changed to improve its operation.

First, Western Power argues that NEMMCO could be required to monitor load forecasts and inform market participants of inaccuracies and deviations from predictions. This would prevent over or under commitment of generating plant in the short term and inefficient investment in generation and network facilities in the longer term (clause 4.9.1(g)).

Second, the Reliability Panel, on advice from NEMMCO and NSPs, could determine a standardised method of calculating current ratings of transmission lines and other plant to avoid NSPs using different methods (clause 4.2.2(c) and (d)).

Third, three phase faults may be considered a credible contingency on some parts of the power system, and therefore should be included in the Code's definition of a credible contingency event. Moreover, there is an apparent conflict between clauses in Chapter 4 (clause 4.2.3(b)(2) and 4.2.3(e)) which exclude three phase faults as a credible contingency event, and a clause in a Chapter 5 schedule (i.e. s5.1.2.1) which includes such an event in some circumstances.

Other suggestions made by Western Power in their review of Chapter 4 were to simplify and clarify particular clauses (especially clause 4.2.3(c) and 4.3.2(d)) and to correct typographical and cross referencing errors.

Colin Taylor's review of the Western Power report argues that there may be a need for NEMMCO to have some level of accountability to market participants for the accuracy of its load forecasts. He suggests that NEMMCO could publish statistical data on the accuracy of the load forecasts and an explanation of significant errors. Colin Taylor also suggests that:

- the provision requiring Code participants to provide voice and data communications equipment may be a barrier for small participants and should therefore only apply to participants with connections above 10MW; and
- it may need to be recognised that the requirement for generating units to have governor systems is not applicable to some forms of generation.

Commission considerations

The Commission accepts the applicant's view that it is necessary for the Code to prescribe the responsibilities of NEMMCO and all Code participants. This approach protects the interests of new entrants as they are given certainty about the standards at which the power system is to be operated and their obligations for maintaining system security.

The interests of NSPs, network users and the public are also protected by the system security requirements which promote a safe and reliable means of generating and transporting electricity, reduce the risk of a system wide disruption and seek to restore the power system and minimise the impact after such a disruption.

While similar system security practices are used across the electricity industry operational differences exist and, as a result, there currently is no industry wide standard. The power system security requirements of the Code protect the interests of NSPs, network users, the public and potential entrants by codifying a set of practices which are generally consistent with those used throughout the industry, and hence have an associated public benefit.

The Commission accepts Western Power's conclusion that the power system requirements do not disadvantage new entrants relative to incumbent NSPs. While the requirement for Code participants to provide load forecast information may be viewed as a disadvantage to new entrants because of set up costs, it is acknowledged that ongoing costs should be small, and it is likely participants would need to produce this type of information for use in their businesses anyway. At a broader level, it is argued that load forecasts published by NEMMCO are important to the wholesale market in order to maintain reliability of supply. Inaccurate load forecasts can create inefficient market signals, such as inappropriate supply or demand side responses. Hence it is appropriate that NEMMCO monitor the accuracy of load forecasts.

The Commission considers that it would be in the interests of all parties to further improve the clarity and operation of the Code by reconsidering Western Power's suggestions and recommendations. While it is likely that many of these issues were considered in preparing the Code, the Commission believes that it is necessary for the applicants to revisit them in light of the consultants' comments. Western Power's recommendations include reviewing:

(i) whether three phase faults should be included in the definition of a credible contingency event;

(ii) whether NEMMCO should monitor load forecasts and inform market participants of inaccuracies and deviations from predictions;

(iii) the apparent conflict between clauses 4.2.3(b)(2) and 4.2.3(e) and clause S5.1.2.1;

(iv) whether the Reliability Panel, on advice from NEMMCO and NSPs, should determine a standardised method of calculating current ratings of transmission lines and other plant;

(v) clauses 4.2.3(c) and 4.3.2(d);

(vi) the provision requiring Code participants to provide voice and data communications equipment so that it only applies to participants with connections above 10MW; and

(vii) the provision requiring all generating units to have governor systems, since it may not be applicable to some forms of generation.

9.2 Procedures to maintain power system security and reliability of supply

Generation capacity and the capability of the network determine the ability of the system to match supply with demand. There are severe economic and social consequences of the market failing to balance supply and demand and hence the Code includes provisions for NEMMCO to intervene in the market in regard to a number of specific circumstances. [70]

Market intervention can occur either on the supply side or the demand side. Supply side intervention has the objective of bringing more generating capacity to the market. Demand side intervention typically takes the form of controlled load shedding. Load shedding has a direct impact on the general public and consequently is seen to be less desirable than supply side intervention.

This section examines each of the intervention provisions in the Code.

9.2.1 The reserve trading function and powers of direction

If a violation of power system security, a lack of reserves or low reserves condition is forecast, NEMMCO must follow the process outlined in Figure 9.2.1. Where NEMMCO has dispatched reserve plant or issued a direction, that dispatch interval is to be known as an intervention price interval (clause 3.9.3), and participants are entitled to receive compensation according to clause 3.14.11.

NEMMCO must ensure it maintains separate accounts relating to its reserve trading activities, and if plant under reserve contract is dispatched, NEMMCO must report on the circumstances according to clause 3.15.8. Where either intervention has occurred or a region requires a higher level of power system reliability or reserve, NEMMCO will recover its net liabilities from the market customers in that region in accordance with clause 3.17.9.

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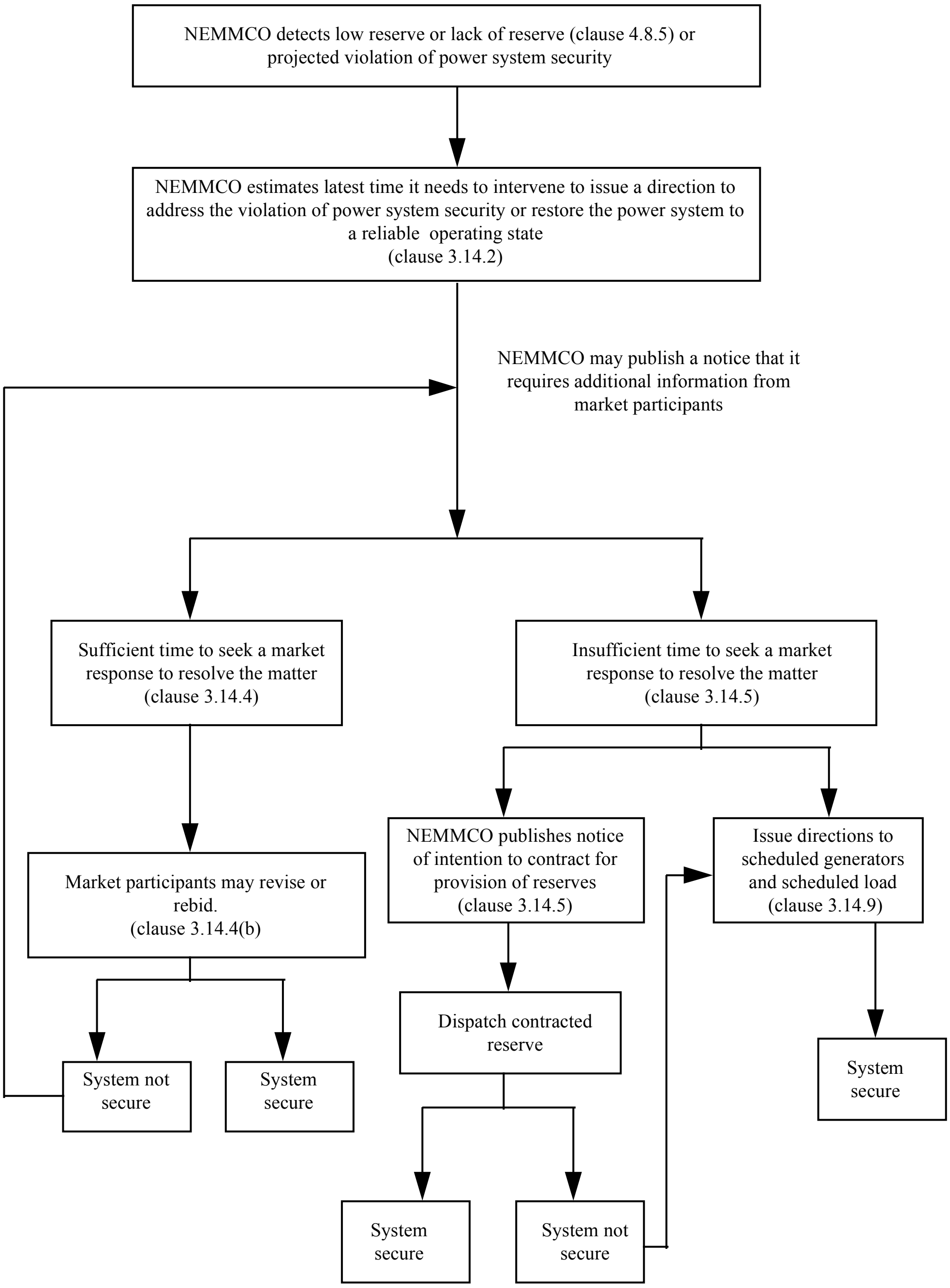
[70] The interventions discussed in this section are distinct from interventions used to balance supply and demand within a half hour spot trading interval, that is, ancillary services.

Figure 9.2.1 Power System Security



Issues for the Commission

The Commission considers the reserve trading provisions could be anti-competitive in that NEMMCO's intervention could substantially lessen competition in the spot market between generators and/or scheduled load. For example, participants in the wholesale pool may behave in a way which secures contracts with the reserve trader. Central provision of reserves may also diminish incentives for market based approaches, as participants may come to rely on central intervention.

The arrangements by which NEMMCO is required to issue directions to maintain a reliable operating state or maintain power system security could also be anti-competitive in that NEMMCO's intervention could also substantially lessen competition in the spot market.

What the interested parties say

In relation to the reserve trading function, TransGrid, Macquarie Generation, the Victorian DBs and the EUG argue that the reserve trading function has the potential to distort spot market arrangements.

Both Macquarie Generation and the Victorian DBs believe the reserve trader function is not required and that similar outcomes can be achieved by NEMMCO's intervention under its general powers of direction. In fact, the EUG considers contracting for reserve capacity can be handled by the market without a requirement on NEMMCO to contract for such capacity. However, if NEMMCO retains its role, the EUG argues this function should be reviewed (in full consultation with end use customers) after two (not five) years.

In determining the amount and value of reserve plant, the Victorian DBs submit that the Reliability Panel should be constrained to setting criteria which do not give rise to an implicit value of VoLL. They say that the idea of 'sufficient reserve at any cost' must be avoided.

Both TransGrid and VPX endorse the intervention powers given to NEMMCO, and agree that intervention should only occur once normal market behaviour has failed to deliver the physical outcomes necessary to maintain minimum power system security levels.

The South Australian Government strongly supports a number of the Code provisions which are intended to ensure reliable electricity supplies. The South Australian Government contends it remains to be proven whether an appropriate level of reliability will ultimately be maintained in the longer term solely through the operation of market forces with the present market design. In particular, it says its primary concerns centre on market effectiveness in appropriately remunerating supply side capacity or demand side response which will only be called on very infrequently. Consequently, the South Australian Government states that it cannot leave the reliability of its electricity supplies to either the vagaries of an immature market or the outcomes of a market where the adequacy of some design features is still uncertain. Given its reserve situation, the South Australian Government expects early action by the reserve trader upon market commencement. It says any potential market detriment associated with the use of the Code measures in the first few years of the NEM are likely to be of little significance in comparison to the impact of supply deficiencies on the public benefit.

What the applicants say

The applicants state the requirement on NEMMCO to contract for reserves is a transitional measure until confidence is gained in the ability of market-based signals to deliver adequate system reserves and reduce the risk of involuntary load shedding.

The applicants contend, given the immaturity of the market in its initial years, this transitional safety net feature is in the public interest because it avoids the potential risk of market failure and involuntary load shedding. Hence, they state the arrangements provide public benefits which exceed any anti-competitive detriment which might accrue to some market participants. Further, they argue that customer confidence in the market will be weakened if involuntary load shedding occurs due to a lack of reserves if NEMMCO could have acted to prevent it.

The applicants note that NEMMCO's powers of direction are essential for ensuring system security and the reliability of the system within operational constraints. The applicants add that without such powers there can be no electric power system of the type on which consumers and participants have traditionally relied. The applicants state that in complying with NEMMCO's directions, a participant may not be compensated either at all or fully for the cost incurred in compliance with the directions. They say that in deciding whether to become registered, a participant will need to assess the risks of being in the ESI and take appropriate measures to reduce the level of financial exposure. The applicants note that the wholesale electricity market is for substantial players in the market, who should have the necessary resources and knowledge.

The applicants note NEMMCO's powers of direction in response to a projected lack of reserve condition is a safety net provision in the Code and like NEMMCO's reserve trading activity, this intervention power has a five year sunset clause.

Issues arising from the draft determination

The draft determination imposed the following conditions of authorisation.

C9.1 The reserve trader provisions, clause 3.14 and Chapter 4, must end two years after NEM commencement.

C9.2 Clause 8.8.1(d) must be amended so that the guidelines and policies to be determined by the Reliability Panel to govern the exercise of the reserve trader function are publicly available prior to NEM commencement, following compliance with the Code consultation procedures.

C9.3 NECA must conduct an annual review of NEMMCO's use of its powers of direction under clause 4.8.10. The review must be conducted on each anniversary of NEM commencement in respect of the preceding year. The annual review must consider for each occasion on which the power was used in the preceding year, whether the exercise and manner of exercise of the power was appropriate in all the circumstances and in accordance with the Code objectives and make any recommendations considered appropriate for future exercise of the power. The report of the review is to be completed within 30 days of the end of each relevant year and is to be made available to all market participants.

The Commission received several submissions on the condition to remove the reserve trader provisions two years after market commencement.

Pacific Power supports the removal of the reserve trader provisions and considers that condition C9.1 is consistent with the removal of many of the market based derogations or interventions by 2000.

CitiPower agrees that the reserve trader provisions should be removed as soon as possible and consider that there should be a review mechanism to determine whether an earlier end date is practical. Eastern Energy also supports the early removal of the reserve trader provisions.

Hazelwood supports the thrust of the Commission's stance that intervention should be minimised, but recommend the results of the Victorian capacity support program for the 1997/98 summer be considered before a decision is made to remove the reserve trader.

The ACA supports the condition to phase out the reserve trader, however it is not convinced that the market will deliver the right outcomes. The ACA states that it believes that network price signals can play an important role in signalling peak capacity and proposes that the issue of security of supply and signals for peak capacity be dealt with in a NECA review.

Solaris agrees with the removal of the reserve trader but would prefer an end date of the end of a financial year.

Ecogen Energy argues against the condition of authorisation which requires an end to NEMMCO's reserve trading function two years after market commencement. It argues that without the reserve trading function, there is not enough incentive for market participant to deliver historical levels of reserves because the value of VoLL is too low and will therefore not deliver enough returns for peaking generators to stay in the market.

Ecogen Energy states that if historical levels of reserve are to be maintained, there will need to be capacity payments or the institutionalisation of the reserve trader function, or, if the reserve trader function is removed then NEMMCO's power to intervene to direct market participants to provide reserves should also be removed.

United Energy comments that the removal of the reserve trader function two years after market commencement will create a level of uncertainty regarding supply reliability which is socially and politically unacceptable to governments. United Energy is concerned with the risk associated with the actions that governments may take if they are faced with the possibility of involuntary load shedding. United Energy suggests leaving the reserve trader provisions in the Code for longer than two years, but structure the Code so as to minimise the likelihood of the reserve trader being needed. It suggests that this could be achieved by requiring the Reliability Panel to set guidelines for the use of the reserve trader that are consistent with the market pricing mechanism.

The Victorian Government is concerned that removing the reserve trader after two years will lead to significant system reliability problems because there may not be the necessary investment to address the capacity problems. Also, the necessary demand side response will not develop unless the risks associated with high spot prices are substantially increased.

The Victorian Government suggests that there should be an immediate review of the NEM design to address interrelated issues such as system reliability and reserve, system security standards, ancillary services, force majeure, the level and definition of VoLL and demand side management. It considers that the reserve trader provisions should not be removed until changes to the market design have been made.

The Victorian Government supports NECA's submission that the period of operation of the reserve trader should be sufficiently long to ensure that there can be experience of at least two summer peak loads.

Boral Energy is concerned about the level of regulatory activity in the Victorian jurisdiction in relation to system security. Boral states that further intervention in the 'top end' of the market will delay even longer the ability for market forces to adequately respond to the need for appropriate investment in generation capacity.

The South Australian Government argues that there may still be a need for the reserve trader once the market has reached maturity. This is because the current market design may not provide appropriate market mechanisms and significant refinements may be needed before satisfactory market driven solutions. South Australia argues that they will require additional capacity to meet peak demand by about 2001. South Australia considers that they will require a reserve trader for five years, considering the lead time for market driven new investment initiatives. Unlike New South Wales and Victoria, South Australia does not have any mothballed plant that could be recommissioned.

The EUG states that network prices should be used to signal peak capacity requirements and that such issues should be dealt with as part of the NECA pricing review.

Several generators suggested the removal of NEMMCO's power to direct market participants to provide reserves at the same time the reserve trader function is removed. They considered that NEMMCO's power to direct for system security reasons needs to be maintained.

The BCA/EWG would prefer to see a market structure and rules that minimise the need for the reserve trader function.

SMHEA rejects the suggestion that there should be capacity payments or direct intervention. It recommends the removal of the direct intervention provisions at the same time the reserve trader provisions are deleted. It states that the preconditions for the removal of the reserve trader are likely to include an increase in VoLL (to at least $25 000/MWh) and clarification of the co-dispatch of energy and ancillary services under conditions of supply scarcity.

While agreeing with the principle of condition C9.2, TransGrid considers that the commencement of the NEM should not be delayed if this cannot be achieved.

TransGrid also recommends that the Annual Review of NEMMCO's direction powers required by condition C9.3, should be completed within forty business days, rather than the thirty days recommended in the draft determination.

Commission considerations

Power of direction (clause 4.8.10)

Under clause 4.8.10 and the NEL (section 76), NEMMCO has powers of direction to maintain public safety and power system security. NEMMCO has the power to bypass the Code's market intervention processes (clause 3.14) if it considers that it is appropriate to do so (clause 4.8.10(d)). The Commission endorses Western Power's recommendation that there be an audit of NEMMCO's use of this power to demonstrate to Code participants that it is not being abused or used unnecessarily.

Reserve trading function and power of direction

NEMMCO has a reserve trading function (clause 3.14) and if commercial reserve trading negotiations fail to address a projected low reserve or lack of reserve condition, clause 4.8.6 allows NEMMCO to intervene as a last resort to direct scheduled generators or market customers to make plant available. Direction is given in order to avoid a breach of the minimum reliability standards as determined by the Reliability Panel.[71] The Code states that this power of direction will terminate along with the termination of the reserve trading function five years after market commencement.

NEMMCO's ability to contract for reserves, along with its power to direct the market, other than in emergency or extreme circumstances, raises concerns as it represents interference with a business which may be perceived as interference with the rights of the owner of that business.

Due to these concerns the Commission has assessed this Code provision and observes that there are four options.

(i) Have neither a reserve trading function nor a power to direct

It is expected that when the market reaches maturity, the market itself will operate in such a way that all the participants will respond to price and information signals, and that the market will clear of its own accord without the need for intervention by NEMMCO. When this occurs NEMMCO will not intervene in the market unless there is a major emergency event, as determined under clause 4.8.10. However, it is not clear that the risk of market failure is sufficiently low at present to make this option feasible.

If both the reserve trader and intervention powers are removed and there are insufficient reserves provided by the market, then there would be an increased risk of load shedding. Several generators have argued that the market should be prepared for the risk of the lights going out if it does not adequately value reserves. However, this would not be acceptable to the jurisdictions, as the public has come to expect a reliable electricity supply.

Recent summer demand in Victoria has highlighted the problems of low reserve and altered perceptions on the level of excess generating capacity in the eastern States. Furthermore, the high expectation of the community regarding system reliability also supports the case that the Australian community expects the NEM to maintain current reliability levels. Consequently, there may be a case to allow for some form of intervention to minimise the chances of load shedding in the initial stages of the market, especially until such time as both the supply and the demand side are more familiar with the market arrangements and have developed appropriate responses.

(ii) Preserve the reserve trading function but have no power to direct

Having the reserve trading function without powers of direction could result in market participants acting to maximise payments under reserves contracts, to the detriment of overall market outcomes. A market participant could hold off providing adequate reserve in order to

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71 Issues regarding the Reliability Panel are discussed in section 13.6.

secure a contract with the reserve trader. In such circumstances the cost of procuring reserve will rise, especially if the brief of the reserve trader is to maintain system security at all costs. The power of direction prevents this behaviour because if sufficient reserve is not available for contract at a reasonable price NEMMCO can direct Scheduled Generators or market participants to do any act or thing NEMMCO deems necessary to maintain or re-establish the power system in a reliable operating state.

However, the presence of the reserve trader has the potential to create a number of market distortions and these are detailed in (iv) below.

(iii) Preserve the power to direct but have no reserve trading function

Without the reserve trading provisions NEMMCO's only avenue for intervening in response to a projected lack of reserve would be through its powers of direction. Decisions as to which plants should be targeted for direction may tend to be based primarily on operational conditions and lack the commercial basis that the reserve contracting provisions would provide.

Moreover, this has cost and equity implications where a region has agreed to accept a higher level of security than that specified in the power system security and reliability standards. This is because such a region may face direction more often than regions that have accepted lower standards. Going straight to direction means that the cost of a region accepting a higher standard of reliability may not be appropriately recovered.

(iv) Preserve the reserve trader and NEMMCO's powers of direction

The combination of the reserve trading function and NEMMCO's powers of direction prevent attempts to manipulate reserve trading contract payments while also allowing NEMMCO's powers of intervention in the spot market to be as commercially based as possible. In this regard the reserve trader can be described as providing a buffer between a competitive market and a directed market, which may minimise the need for direction in the early stages of the market. However, the reserve trader does not provide a solution to all possible causes of the market failure — particularly the failure of the market to provide an adequate return for marginal plant or load. VoLL is a fundamental market signal in regard to long term investment in reserve.[72] If the level of VoLL is set too low, it will materially impact on the overall level of power system reliability. It may discourage investment in new (and possibly encourage mothballing of existing) peaking plant which provides essential reserves for the overall market. That is, a low value of VoLL may contradict the value the community places on system reliability, and if this is the case market intervention will be more frequent than if the value of VoLL was higher.

If not managed properly, the reserve trader has the potential to create a number of distortions through its short term effect on the spot price and its long term effect on investment. For example, despite the provisions of clause 3.14.5(b), if the reserve trader contracts are with a generating plant that would have remained in the market in any case, that plant's contracted capacity will probably be offered into the market at VoLL instead of perhaps a much lower price. Spot prices may be driven upwards as a result. In order to limit the reserve trader's potential to distort spot market outcomes, the Reliability Panel will need to set strict guidelines within which the reserve trader is allowed to operate.

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[72] Discussed in section 8.6.

Another concern, as with all central intervention, is that the presence of the reserve trader will influence the behaviour of market participants, and hence free market trading. Participants may come to rely on the central intervention of the reserve trader in preference to developing market based alternatives. In dispatching reserve, the Code makes a number of provisions in order to minimise the impact of contracted reserve on the spot market outcomes.

Overall assessment

Of the four options considered above it would appear the alternative that preserves the reserve trader and NEMMCO's power to direct may be the most sensible in the initial stages of market development. To have neither implies a risk of load shedding in a market that has as yet little experience. To have one without the other may lead to gaming or inequities.

It needs to be kept in mind that a systematic lack of reserves may indicate a fundamental deficiency in the market. The fact that PASA indicates to the generators and dispatchable loads that there is a strong likelihood of high pool prices should elicit a supply response from generators and a demand response from market customers. Where these indications have failed to attract the generation or dispatchable load to rebid into the market, this may be because:

- the PASA has been inaccurate in the past;
- the minimum reliability margin is overly conservative;
- interventions in the past have led customers to believe that they will be sheltered from supply shortages and the associated high spot price and so they are less inclined to respond; or
- the cost of generating or being dispatched is above VoLL (ie the value of VoLL is set too low).

Thus the provisions need to be monitored and continually assessed in order to limit their potential distortionary impact on the market. The Commission understands that the reserve trader is intended to be an interim entity designed to accommodate the market in its first five years when a lack of maturity may result in unnecessary breaches of the minimum reliability margin, which could lead to involuntary load shedding. Although the Code provisions attempt to minimise distortions, the analysis at this stage of the reserve trader's impact on the market is somewhat speculative. Hence it is a condition of authorisation that the reserve trading provisions of the Code end by 30 June 2000. This allows time for the market to experience two summer peaks in Victoria and to develop the appropriate responses. The market will also have the experience of the capacity support program being implemented by VPX for the 1997/98 summer.

NEMMCO and several participants have suggested that NECA undertake a review of the reserve trader function before it is removed. The Commission considers that this is appropriate and that a review should be held by March 2000. If this review indicates that the market still requires the reserve trader function, then an application for authorisation of the reserve trader beyond June 2000 could be bought to the Commission at this time.

If, following the removal of the reserve trader, the market fails to provide enough reserves, it may be because the standard of reserves set by the reliability panel is too high. NEMMCO argues that rather than ending its direction powers with respect to reserves, generators should raise with the Reliability Panel the possibility of reducing the standard of reserves set in the power system security and reliability standards.

The Commission considers that the public benefits associated with the NEM will be diminished if there is a reduction in the historical level of electricity supply reliability. Therefore the Commission considers that NEMMCO's power to direct participants in times of inadequate reserves should be maintained once the reserve trader provisions have been removed in June 2000.

Further, the Commission considers that maintaining the direction powers associated with clause 4.8.6 may provide an incentive for reserves to be provided by the market, since the compensation paid to market participants under direction is likely to be less than what they would receive if they had provided capacity to the market voluntarily.

Given that the reserve trader is only likely to be required to operate in the summer peak (between December and March) the Commission agrees with TransGrid's comment that the commencement of the NEM should not be delayed if the guidelines and policies governing the reserve trader function have not been produced. However, the Commission considers it important that this information is made available to the market well in advance of the 1998/99 summer peak. The Commission therefore imposes the condition of authorisation the guidelines and policies must be completed by June 1998.

TransGrid has recommended that the Annual Review of NEMMCO's direction powers, required as a condition of authorisation, should be completed within forty business days, rather than thirty days. The Commission considers that thirty days is sufficient time given that a substantial amount of the work towards the review can be conducted after each instance of direction rather the entire review occurring at the end of the year.

Conditions of authorisation

C9.1 The Code must be amended to provide that the reserve trader provisions, contained in clauses 3.14 and 4.8.6 of the Code, end on 30 June 2000.

C9.2 The Code must be amended to provide that NECA must conduct and complete a review of the reserve trader provisions by 30 March 2000. The review must consider the adequacy and the appropriateness of the reserve trader provisions, whether there is a need for a reserve trader in the market, whether there are any alternatives to the reserve trader provisions, whether there are any distortions to market outcomes caused by the reserve trader provisions, and whether there are any alternative provisions which might be added or substituted therefore, in meeting and facilitating the Code objectives. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C9.3 Clause 8.8.1(d) must be amended to provide that the guidelines and policies to be determined by the Reliability Panel to govern the exercise of the reserve trader function are publicly available by 30 June 1998.

C9.4 The Code must be amended to provide that NECA must conduct an annual review of NEMMCO's use of its powers of direction under clause 4.8.10. The review must be conducted on each anniversary of NEM commencement in respect of the preceding year. The annual review must consider for each

occasion on which the power was used in the preceding year, whether the exercise and manner of exercise of the power was appropriate in all the circumstances and in accordance with the Code objectives and make any recommendations considered appropriate for future exercise of the power. The report of the review is to be completed within 30 days of the end of each relevant year and is to be made available to all market participants.

9.2.2 Force majeure and market suspension

An administered price cap is to apply as described in clause 3.16 for force majeure events[73] and during market suspension. Clause 3.16 is designed for events or circumstances which impact on the NEM to such an extent that it is unable, or considered inappropriate for it, to continue to operate. These circumstances are likely to be extremely rare.[74]

Issues for the Commission

The arrangements in clause 3.16 may be regarded as price fixing, as they entail the imposition of an administered price cap. The arrangements also have significant competition implications for all interconnected regions, and hence may be considered to be provisions which have the purpose or effect of substantially lessening competition.

What the interested parties say

EnergyAustralia notes that Victoria has included site specific industrial actions (or events which result in plant being withdrawn from the market totalling an excess of 550MW) as events which could trigger market suspension. EnergyAustralia does not agree that issues such as site specific industrial actions warrant market suspension.

With regard to the administered price cap compensation payments, energyAustralia does not support the concept of imposing an uplift which market customers cannot hedge against. It notes the treatment of any shortfall as an uplift has caused problems in the UK, and is a potential opening for abuse by generators. It suggests other alternatives need to be implemented which will either place a cap on the total uplift or else add the shortfall to the pool price in a manner that the demand-side of the market can hedge against. A similar point was made by Boral Energy.

The EUG is concerned that emergency services procedures can differ from one jurisdiction to another and can be influenced by political rather than commercial considerations. It is of the view that market suspension should be limited to the latter. It also suggests that suspension may be influenced by problems with the operation of the spot market due to market design issues. In this regard it draws attention to the England/Wales pools which have operated under administered arrangements due to excessive pool prices and, given that users will bear the costs of such conditions, wishes to avoid these in the NEM.

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[73] The Code defines force majeure as 'an event or effect which is neither anticipated nor controllable by the affected parties including acts of nature, governmental interventions and acts of war.' The Code also provides for NECA to develop, authorise and publish a schedule to define force majeure events and prescribe the impacts of a force majeure event which would constitute a material force majeure event.

[74] For example particular circumstances include the failure of information, computer and communication systems, NEMMCO industrial dispute, etc.

The EUG strongly believes that the electricity industry should be made responsible for its actions, and that force majeure may allow it to abrogate from these. It says that if force majeure conditions are accepted by the Commission it is imperative that NECA's definitions be clear and exclude non-commercial conditions. It says that NECA's development of these concepts and the administered price caps to apply to regions need to proceed in full consultation with users. It also notes that the imposition of a uniform levy on customers in affected regions undermines the principle that responsible parties should bear these costs.

What the applicants say

The applicants state that an administered price cap under market suspension or for certain defined material and sustained force majeure events is essential for market participants to manage their contract risks, at least until the market evolves sufficiently for alternative commercial risk management strategies to be developed. Alternative individual-by-individual contracts would impose high transaction costs on the market and are unlikely to lead to a significant level of co-ordination to result in a smoothly operating response to force majeure events.

The applicants contend that the arrangements are in the public interest because they provide an auditable process by which NEMMCO, NECA, and participating jurisdictions are to be held accountable for market intervention. Moreover, such intervention should only occur when the power system cannot be operated under the market rules to maintain power system security. In this context the applicants say that it is important to note the recommendation made by William M. Mercer and Clayton Utz in their report to the NGMC:

> *'In summary, it is suggested that a clear approach to market suspension be set out in the Code of Conduct which is co-ordinated by NEMMCO. Given the extremely limited circumstances in which market suspension is likely to occur, a highly pragmatic approach is suggested. More sophisticated approaches could be adopted but the added complexity does not seem warranted at this time.'*[75]

Issues arising from the draft determination

The draft determination imposed the following conditions on authorisation:

C9.4 Clause 3.16.2(a) must be amended to include the schedule NECA must develop to define a force majeure event, prior to NEM commencement.

C9.7 NECA must, within 60 days of the third occurrence in any two year period of a force majeure event (as defined from time to time pursuant to clause 3.16.2(a)) or in any event within five years of the NEM commencement, conduct and complete a review of the provisions of clause 3.16. The review must consider the adequacy and appropriateness of the provisions, and of any alternative provisions that might be added or substituted thereof, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

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[75] William M. Mercer and Clayton Utz, *Market Suspension Criteria and Pricing,* December 1995, (page 2).

In its submission following the pre-decision conference, Macquarie Generation states that it supports the Commission's draft determination with respect to force majeure events. The Victorian Government supports the inclusion in the Code of a definition of force majeure events and the description of the force majeure events that would constitute a material force majeure event.

The Commission understands that progress is being made on this matter, with the Victorian Government preparing a proposal defining force majeure events and outlining the procedure for declaration of a material force majeure event, which will be discussed with the applicants and other jurisdictions.

As a matter of clarification, the Commission has amended the condition to reflect its intention that the schedule also prescribe the impacts of a force majeure event (or combination of force majeure events in each region), which would constitute a material force majeure event.

TransGrid comments that 80 days is a more appropriate time period for NECA to effectively conduct a review of the provisions within clause 3.16 in accordance with the Code consultation procedures.

Commission considerations

In considering the provisions in clause 3.16 the following points are made.

Responsibility

Examination of comparable markets to the NEM indicates that suspension criteria also apply to those markets.[76] As provided for in clause 3.16, NEMMCO is best placed to judge whether market suspension is warranted as only it is in a position to process the relevant information and make a decision within a short timeframe.

There may be some uncertainty for market participants because the triggering of market suspension will depend in part on NEMMCO's judgement. Concerns that NEMMCO could exercise its market suspension powers for reasons other than because the market cannot continue to operate have been addressed by the inclusion of an express prohibition on NEMMCO exercising its powers for events which are not considered to warrant market suspension (clause 3.16.3(b)).

The formal involvement of participating jurisdictions in the operation of the NEM may well be perceived to be undesirable. However, clause 3.13.3(a) provides that NEMMCO *may* declare the spot market suspended in a region if it is directed to do so by a participating jurisdiction, following declaration by that participating jurisdiction of a state of emergency. It is therefore essential that participating jurisdictions limit the scope for their interference, and consider harmonising, as far as possible, emergency services legislation regarding electricity matters.

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[76] In 1995 the NGMC undertook a major consultancy program. Mega Brief O examined the operation of the reserve trader. The brief examined comparable markets including the Sydney Futures Exchange, the Australian Stock Exchange and the England and Wales Wholesale Electricity Market.

Force majeure

NECA is to determine in conjunction with the participating jurisdictions a schedule defining force majeure events. The Commission has concerns about the openness of this clause and what may be defined to constitute a force majeure event. The Commission's concerns in relation to the Code being used to manage commercial risk, in the context of the Victorian Industrial Relations Force Majeure (IRFM) provisions (clause 9.5.4) were discussed in detail in the *NEM1 Stage 1 Working Paper, March* 1997.

The Code provides that if a force majeure event prevails for 24 hours then NEMMCO must invoke the administered price cap (clause 3.16.2). This time limit is arbitrary and is based on the premise that the continuation of the force majeure event may highlight a more fundamental problem in the market and to allow the market to remain operating possibly exposes participants to unacceptable levels of risk. However, the significance of the force majeure event in terms of its impact on the market really depends on what constituted the event in the first place and comes back to the need to carefully define force majeure events.

It is not clear from the Code whether the definition of a force majeure event will be uniform between the participating jurisdictions. Non-uniformity creates uncertainty and the possibility of inequitable treatment of participants in different regions.

Procedures

NEMMCO is required to notify the commencement and cessation of an administered price period. In the case of force majeure, NEMMCO is to notify market participants (clause 3.16.2(b)) and in the case of market suspension NEMMCO is to notify Code participants (clause 3.16.4(a)). It is not clear why this distinction has been made and it is considered unwarranted. The clauses should be aligned so that NEMMCO must publish the occurrence of such events to all Code participants via the market information bulletin board. NEMMCO should also endeavour to provide Code participants and interested parties with as much information as possible concerning potential and actual suspension events.

The Commission considers that the clause 3.16.2(f) of the Code does not clearly define the requirements for ending the administered price period. The Commission therefore recommends that the Code be clarified to specify how the end of an administered price period is determined.

Administered price cap

There are a variety of possible methods for setting an administered price cap, such as taking the last available spot price, or the average price over a defined period. A pricing approach which seeks to replicate the market if it had not been suspended is preferable. The Commission recommends that the pricing approach be the same under all circumstances and across the regions, otherwise there is the potential to give for uncertainty and dispute.

Investigation

Suspension of the market or the imposition of an administered price cap following a force majeure event are drastic occurrences, and are likely to impact on market confidence. To ensure transparency it is appropriate to provide for a formal investigation of all aspects of the market suspension or force majeure event soon after the suspension or force majeure event is resolved. To facilitate this process NEMMCO should be required to keep records of all actions taken during such periods. Code participants may also be called upon to provide evidence. The results should be distributed to all Code participants and provided to interested parties on request.

Review of clause 3.16

It can be assumed that the market will learn from experience in relation to the types of situations that may warrant the application of an administered price cap, and the procedures and prices that should be applied during such periods. It may be that the rules in the Code do not address all circumstances. In particular, if the rules were invoked often, or were invoked and were to continue for a prolonged period, it may be that a different approach is required. The approach adopted in the Code at this stage may be adequate, however, the clauses should be reviewed after a sufficient period.

Conditions of authorisation

C9.5 Clause 3.16.2(a) must be amended to provide that a schedule detailing the matters in clause 3.16.2(a)(1) and (2) is included in the Code.

C9.6 Clause 3.16.2(b) and 3.16.4(a) must be amended to provide that NEMMCO:

(a) must publish on the market information bulletin board, or

(b) otherwise notify without delay,

a material force majeure event or declaration of market suspension.

C9.7 Clause 3.16.4 must be amended to provide that:

(a) within 10 workings days of the suspension being resolved, NEMMCO must undertake an investigation of all aspects of that market suspension; and

(b) NEMMCO must as soon as possible provide a report on the results of the investigation, and must distribute this report to all Code participants as soon as possible and to all interested persons upon request.

C9.8 The Code must be amended to provide that NECA must, within 80 days of the third occurrence in any two year period of a force majeure event (as defined from time to time pursuant to clause 3.16.2(a)) or in any event within five years of the NEM commencement, conduct and complete a review of the provisions of clause 3.16. The review must consider the adequacy and appropriateness of the provisions, and of any alternative provisions that might be added or substituted thereof, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

9.2.3 Load shedding

If the power system cannot be operated in a secure operating state, load shedding occurs. Load shedding which is not part of a dispatch instruction will occur in conjunction with

NEMMCO's powers of direction. Participating jurisdictions will advise NEMMCO of sensitive loads and priority of load shedding.

In addition, the provisions in Chapter 4 place a number of obligations on Code participants with regard to load shedding.

Issue for the Commission

The issue for the Commission is that where load shedding is required, the priority load shedding schedule may confer a commercial advantage on a particular group of market customers and/or end use consumers.

What the interested parties say

The Victorian DBs wish to ensure that the Code gives them access to details about sensitive loads and priority load shedding schedules. The Victorian DBs claim that access to information about sensitive loads and priority load shedding will enable them to make appropriate arrangements under connection agreements to take steps to protect the safety of persons and equipment in the event that NEMMCO begins to shed load in accordance with the priority load shedding schedule, and to assist in protection of sensitive loads as necessary.

What the applicants say

The applicants do not specifically analyse the competitive effects of load shedding provisions in their submission.

Issues arising from the draft determination

The draft determination imposed the following conditions on authorisation:

C9.8 Clause 4.1.1(b) must be amended to enable NEMMCO to notify distribution NSPs of priority load shedding schedules.

TransGrid supported this condition but recommended that it be the responsibility of a System Operator nominated by each participating jurisdiction since NEMMCO plays no part in deciding these priorities.

CitiPower agreed with this condition providing the requirements of the relevant jurisdiction are taken into account regarding sensitive loads.

The incumbent New South Wales distribution network service providers (DNSPs) pointed out that the priority load schedules are not developed by NEMMCO or the system operator. The DNSP develops the priority load shedding schedule for its network based on state government guidelines. This information is then passed on to the existing Regional System Operator.

Commission considerations

The Commission is concerned that the Code does not provide guidelines to clearly define 'sensitive load', although the Commission understands that sensitive load constitutes community facilities, such as hospitals and street lighting, and that sensitive load guidelines will be set by state governments. DNSPs will determine load shedding priorities in accordance with the state guidelines and notify NEMMCO accordingly. The Code appears to contain adequate provisions with respect to the information requirements of DBs.

9.2.4 Pricing for constrained-on scheduled generating units

Clause 3.9.7 of the Code sets out the principles for the pricing of constrained-on scheduled generating units. In the event of an intra-regional network constraint, a constrained-on generator is not entitled to receive any compensation from NEMMCO due to its dispatch price being less than its dispatch offer price (bid price).[77]

Issues for the Commission

Clause 3.9.7 of the Code may be considered to be:

- a price fixing provision in contravention of s. 45 of the TPA, because participants are agreeing that a particular pricing mechanism will be used to determine prices to be charged for constrained-on generating units; or
- a provision having the purpose or effect of substantially lessening competition, in that the requirement to trade at particular prices lessens competition in the NEM.

What the interested parties say

The SMHEA is of the view that clause 3.9.7 is totally contrary to the basic principles of contracting. The generator, it argues, has made an offer and NEMMCO has accepted this offer on behalf of the market by dispatching the generator. Accordingly it claims that NEMMCO should not be allowed to pay the generator any less than the price the generator offered.

The SMHEA has further concerns about the effect of this clause if it was combined with an inappropriate choice of region. If there were high prices in Victoria and only one New South Wales region, the SMHEA could be significantly 'short-changed' in the event of an intra-regional constraint between Snowy and the Sydney regional reference node if the link between Snowy and Victoria is not constrained.[78]

What the applicants say

The applicants do not explicitly analyse the competitive effects of clause 3.9.7 in their submission.

Issues arising from the draft determination

In comments made at the pre-decision conference and in subsequent submissions made to the Commission, several generators disagreed with the Commission's draft determination, which did not impose any conditions on the Code's provisions for the pricing of constrained-on generation.

In a joint submission, the incumbent New South Wales, South Australian and Victorian generators argued that NEMMCO should pay constrained-on generators their bid price and NEMMCO should recover the money from the NSP. They argue that this provides the NSP

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[77] The dispatch price is defined as the price determined for each regional reference node by the dispatch algorithm each time it is run by NEMMCO, while the dispatch offer price is defined as the price submitted by a scheduled generator for a price band and a trading interval in a dispatch offer.

[78] The Code's treatment of regions is discussed in section 8.2.

with the financial driver to determine whether it is cheaper to augment the network or negotiate with the generator for provision of the service.

The generators argue that the Commission's concerns about possible abuse of market power by constrained-on generators should be dealt with through full disclosure of market data and monitoring by retailers, NECA/NEMMCO, the generators or the ACCC.

SMHEA argues that the Commission's concerns about misuse of market power should be dealt with through processes analogous to those envisaged in the Code for ancillary services, where similar considerations apply. Another option proposed by SMHEA and Southern Hydro was for the Code's dispute resolution procedures to be used if there is an issue of abuse of market power.

Ecogen Energy argues that there should be appropriate incentives for the NSP to secure contracts with generators which could be constrained-on. It argues that there is no incentive for the NSP to negotiate in good faith with a constrained-on generator because the market operator can direct the generator to operate for the purpose of maintaining system security.

The ACA argues that the constrained-on generator should be able to set the pool price, otherwise there will be no signals for the market to deal with network constraints. As an alternative, the ACA suggests that there should be more regions. The ACA argues that the issue of constrained-on generation is linked to system security, network augmentation, firm access, locationally efficient pricing and the treatment of ancillary services and that these issues should be considered within a NECA review.

Australian Paper states that the issue of constrained-on generation is linked to transmission pricing. It argues that requiring generators to pay transmission use of system (TUOS) charges would give them greater negotiating power to request the NSP to provide a reliable network. The EUG argues that imposing TUOS charges on generators would encourage NSPs to be more accountable for the performance of their system.

Optima Energy accepts the intent that a constrained-on generator should not be able to set the pool price, however it argues that the Code should provide an explicit right to compensation. It argues that clause 3.9.7(b) removes the ability for a generator to seek compensation.

SMHEA comments that the problems associated with constrained-on generation will be minimised if the likely constraint points lie on region boundaries.

Commission consideration

The Commission disagrees with the incumbent generators' suggestion that NEMMCO should pay generators their bid price and recover the cost from NSPs. Firstly, the Commission considers that constrained-on generators could be capable of predicting where network constraints may arise and use this knowledge to raise the price they receive. This would be a particularly relevant consideration if constraints are such that particular generators are in a position to obtain local market power.

Secondly, the Commission considers that actions by NEMMCO may distort the market in managing the risk associated with a duty to compensate constrained-on generators. This may arise from NEMMCO buying insurance to cover its risk and including the cost of the insurance premium in pool fees.

In response to Optima Energy's concern that clause 3.9.7(b) removes the ability of a generator to seek compensation, the Commission notes that this clause only prevents compensation from NEMMCO.

Several participants raised concerns with the lack of incentives for NSPs to enter into a contract with generators to compensate them for remaining available and further compensate them for generating in times of an intra-regional network constraint.

Clause 5.5(f)(4) of the Code currently states that "the NSP shall negotiate in good faith to reach agreement as appropriate on the compensation to be provided by the NSP to the generator in the event that the generating units or group of generating units of the generator are *constrained-off* during a trading interval".

The Commission has been advised by NEMMCO that the intent of this clause was for the NSP to negotiate in good faith with the generator for compensation in the event that the generator is *constrained-off* or *constrained-on*. The Commission therefore makes it a condition of authorisation that this clause be amended to reflect this intent.

The Commission considers that in order to satisfy the requirement to negotiate in good faith, the NSP would be required to make a reasonable offer of compensation to the constrained-on generator. If the NSP did not negotiate in good faith, then the constrained-on generator could seek recourse through either the dispute resolution or Code breach processes.

The EUG and Australian Paper have suggested that imposing TUOS charges on generators would give generators more bargaining power to demand a higher level of service from the NSP. However, imposing TUOS charges on generators will not directly solve the problem of compensating constrained-on generators. In this situation, generators would pay for the network and would seek a certain level of network reliability, however the overall level of revenue the NSP receives from TUOS charges will not change.

The NSPs will need to manage the risk of having to provide compensation for constrained-on generators. If the NSP does this by insuring against a claim by constrained-on generators, the insurance premiums will be high (because of the risk and uncertainty) and may place a financial burden on NSPs, given that they face a regulated revenue stream. Even if NSPs self insured by auctioning firm access, they would need to cover themselves for the risk of underpricing firm access.

The Commission understands that the frequency of transmission outages, leading to constrained-on generation, is quite small, being only 2-3 times a year in New South Wales and less often in Victoria. The Commission does however understand that constrained-on generation may occur more frequently in Queensland due to the nature of the network.

The Commission also notes that generators can influence the frequency of network constraints. A generator can agree with the NSP to perform their maintenance at the same time so that there is only a lack of supply on one occasion rather than twice.

The Commission considers that the Code (with the amendments required to be made to clause 5.5(f)(4)) attempts to put in place drivers for NSPs to negotiate contracts with constrained-on generators. While this approach may not represent the ideal solution, the Commission considers that it is more appropriate than giving constrained-on generators the ability to abuse their market power and receive an exorbitant bid price. The Commission also considers that, once amended, clause 5.5(f)(4) is appropriate given the relatively infrequent occurrence of constrained-on generation, especially since generators and NSPs can negotiate to conduct maintenance at the same time.

The Commission, however, believes that the impact and effectiveness of the amended Code provisions for compensating constrained-on generation should be closely monitored. If particular generators are constantly being constrained-on, the reasons for this occurring will need to be examined. The Commission considers that the issue of constrained-on generation is complex as it is linked with other issues such as transmission pricing, firm access and network augmentation. The Commission therefore accepts that the amended Code provisions may not be the ideal solution and therefore recommends that any changes, if appropriate, could be introduced through the Code Change Process.

Condition of authorisation

C9.9 Clause 5.5(f)(4) must be amended to provide that:

> **"compensation to be provided by the *Network Service Provider* to the *Generator* in the event that the *generating units* or group of *generating units* of the *Generator* are *constrained-off* or *constrained-on* during a *trading interval*".**

9.2.5 Overall assessment

From the Commission's perspective an assessment needs to be made of whether the provisions in the Code satisfy the following key objectives:

- market intervention should be used as little as possible;
- market intervention should be used only as a last resort and then in a way which seeks to minimise its impact on the market;
- the financial impact of market intervention on a party should be reduced to the extent possible; and
- the NEM should seek to continually develop so that the need for market intervention declines.

The market should be given every opportunity to respond and in this regard the reserve trader provisions in the Code would appear to provide this opportunity. However, the reserve trader provisions have the potential to significantly impact on the behaviour of market participants and hence on market outcomes. Current unfamiliarity with the market arrangements and lack of maturity are reasons for accepting certain powers of intervention. As the market matures it is envisaged that the need to intervene will diminish and the only case for intervention will be for public safety and power system security purposes.

In other cases it is not possible to determine the extent and effectiveness of the arrangements by which NEMMCO will be required to intervene without market experience. As Integral Energy notes, the introduction of the NEM will cause changes to the pattern and mode of operation of all generators. Therefore, past behaviour may not be a good guide to the future.

The Code does provide for NEMMCO to conduct a review of significant operating incidents or deviations from normal operating conditions. The review is to assess the adequacy of the provision and response of facilities or services and the appropriateness of action taken to restore or maintain power system security (clause 4.8.16).

Issues arising from the draft determination

Eastern Energy submits that the results of the investigation into operating incidents may contain confidential or sensitive information and it is essential that it only be released with the explicit permission of the owner of the information.

The Commission notes that the provisions within Chapter 8 of the Code, relating to the treatment of confidential information, are not overridden by condition C9.10.

Condition of authorisation

C9.10 Clause 4.8.16 must be amended to provide that the results of any investigation or report in relation to operating incidents, or market suspension, must be distributed to all Code participants, and provided to interested persons on request.

10. Network connection

Chapter 5 of the Code deals with the technical standards required for connection, the procedures to follow in order to achieve a connection agreement, access arrangements for generators, augmentation and planning of networks, testing and inspection of connected equipment and disconnection. The aim of Chapter 5 is to provide non-discriminatory rights of access to natural monopoly networks to enable efficient participation in the NEM, efficient network investment, and set minimum technical standards to ensure security of supply.

Connection to transmission and distribution networks is fundamental to the use of natural monopoly facilities and the realisation of the benefits of competition in both the generation and retail sectors of the ESI. The arrangements for connection set out in the Code form a key component of the access regime and more detailed analysis and discussion of the arrangements can be found in the *NEM Access Code Draft Determination*. However, because of the importance of an effective access regime to upstream and downstream competition, the Commission has considered the competition implications of key provisions in this Determination.

10.1 Technical standards

Chapter 5 and its schedules prescribe default technical standards for equipment connected to the power system, and performance and quality of supply standards. All Code participants are required to maintain and operate equipment that is connected to the network in accordance with relevant laws, the Code and good industry practice (clause 5.2.1).

The technical requirements are default standards. It is possible for an NSP and a Code participant to negotiate alternative standards in connection agreements below or above those set out in the Code, as long as the quality of the service received by other network users is not affected.

Issues for the Commission

The technical standards represent an up-front cost which may create an unjustified cost or inefficiency for participants, may unduly favour some participants relative to others, may lead to inconsistent or discriminatory treatment of participants or may otherwise hinder access without yielding any public benefit. Hence these arrangements may be considered to be exclusionary provisions, exclusive dealing provisions or provisions which may substantially lessen competition.

What the interested parties say

The BCA, Dr Hugh Outhred, SMHEA, the NFF, Environment Australia and Greenpeace raise concerns that technical standards could discourage entry of smaller participants and alternative forms of generation, including renewable generation technologies.

To the contrary TransGrid believes that the NEM design is neutral to generating technologies and argues that the Code's quality requirements are the minimum necessary for the safety and security of the system and to protect customer and network equipment, and are similar to standards used world wide. It argues if new generation technology emerges which is disadvantaged by the present arrangements, this could be managed via the Code change process. Hazelwood Power, Delta Electricity, Ecogen Energy, SMHEA, Australian Paper, TransGrid and Macquarie Generation are concerned about the performance standards placed on NSPs. They argue that the Code arrangements insulate NSPs from the market and commercial risks created by unreliable or constrained networks, yet allow them to collect revenue irrespective of their performance. These submissions contrast the performance requirements on NSPs with the technical obligations on generators, particularly small and alternative energy plant, which are regarded as very onerous.

SMHEA, the EUG, Yallourn Energy, Hazelwood Power, Delta Electricity, TransGrid, Ecogen Energy, energyAustralia and the South Australian Government all voice concern over the obligation to provide ancillary services through negotiated connection agreement and NEMMCO directions, based on technical and system security requirements. They do not think it appropriate for NSPs to provide such services through connection agreements.

The consultant's view

Western Power argues that, in general, the technical requirements will not:

- impose any unnecessary barriers to those seeking entry to the market and/or access to the wires infrastructure;
- place any burden on new providers beyond those necessary to ensure an adequate level of power system security and adequacy of supply; or
- discourage network investment or impede the future development of the market.

Western Power states that without the details of existing arrangements it cannot determine whether current network providers will be advantaged or disadvantaged by the Code requirements, however, existing providers may be advantaged if they do not have to upgrade existing facilities.

Western Power points out the Code could be improved by:

- providing specific information on some requirements (e.g. protection settings, duplicate protection, stability, design standards) to avoid disputes over interpretation;
- highlighting special conditions or exemptions applying to co-generators, embedded generators and alternative generators;
- achieving uniformity between jurisdictions on such issues as the inclusion of three phase faults as credible contingency events for lines operating at or above 220kV;
- making all variations to the requirements of the Code available to all Code participants to ensure consistent and fair application of the requirements; and
- upgrading non-compliant facilities to meet the requirements of the Code when the facilities are eventually replaced.

In summary Western Power believes that, although the requirements of Chapter 5 are quite extensive and prescriptive, they are reasonable and generally in accordance with accepted industry practice and the requirements for ensuring an adequate level of power system security.

What the applicants say

The applicants argue that the specification of technical standards for equipment connected to the network has been designed to ensure that a clear and unambiguous framework is established within which participants can negotiate with NSPs on the terms and conditions for a connection facility and at the same time ensure the integrity of the network to provide the quality of service required by other users.

The applicants argue that the technical standards, despite their different impacts on suppliers and customers, operate in the public interest because without them the power system will not operate safely to convey electricity to end use consumers at an acceptable quality of supply. They also say that the conditions for connection for a generator have been specified in a manner to remove any bias against alternative generation technology, provided the alternative is safe for public use.

The applicants submit that because the standards apply uniformly throughout the NEM they do not discriminate against, nor do they present a barrier to entry for, any participant. In addition, where these standards may be considered to represent a barrier to entry there are adequate dispute resolution procedures to resolve the matter or clause 8.4 can be used to seek a derogation from the Code.

Issues arising from the draft determination

At the pre-decision conference and in subsequent submissions, a number of parties raise the issue of the high level of performance demanded by the technical standards currently in the Code, the net cost of compliance (particularly for generators) and hence the need for continuing derogations. This is contrasted with the satisfactory state of system security at present with the existing derogations (not the Code) setting the actual operating standards. The general tenor of these comments is that the standards need to be reviewed, with the prospect of introducing a set of minimum standards with the capacity to vary these (within acceptable boundaries) to accommodate local conditions. These issues are examined in more detail in section 14.4 of this Determination.

Commission considerations

A full discussion of the Commission's considerations is to be found in section 4.3 of the *NEM Access Code Draft Determination*. A summary of the discussion follows.

Comments from Western Power and interested parties suggest there are a number of concerns regarding the technical requirements applying to generators and more specifically co-generators, embedded generators and alternative generators. The Commission's *NEM Access Code Draft Determination* believes that it is necessary for the applicants to revisit these requirements in light of Western Power's comments and make any necessary Code changes through the Code change process. In addition, it is recommended that NECA review the complexity of technical standards and produce guidelines on the compliance appropriate to different participants.

In light of the concerns raised by interested parties as to the standards of performance placed on NSPs, the Commission's *NEM Access Code Draft Determination* considers that each NSP should formalise their approach to these Code requirements in the form of a binding code of practice or service charter regarding the provision of network and connection asset reliability. The Commission and other relevant regulators could then assess the adequacy of the compliance of individual NSPs with the Code and the service charter.

In respect of ancillary services the Commission's *NEM Access Code Draft Determination* is seeking the NECA review on ancillary services to include an examination of their provision in connection agreements with a view to phasing them out where an ancillary services market can be developed.

10.2 Access undertaking

Clause 5.2.3(a) states that to register with NEMMCO as an NSP the application must be accompanied by an undertaking from the applicant to the Commission that, if the application is approved, the NSP will provide access to its transmission and distribution networks in accordance with the Code.[79] However, according to clause 2.6(d) NECA may, in accordance with the guidelines issued from time to time, exempt any person or class of persons who is or are required to register as an NSP from the requirement to register or from the operation of Chapter 5 and the requirement to provide an access undertaking to the Commission.

Issues for the Commission

The requirement for NSPs to register and give an undertaking to provide access to their networks may be an exclusionary provision.

Obtaining an exemption from the requirement to provide an access undertaking may competitively advantage exempt NSPs compared to non-exempt NSPs.

What the applicants say

The applicants state that the requirements for all NSPs to give an access undertaking for their network services in accordance with the terms of Schedule 5.8 is intended to enable NSPs to be bound to the terms of the Code, in particular its access provisions.

They further submit that the public benefit of a national access regime covering the national grid outweighs any possible anti-competitive detriment caused by the imposition of standards for access and the reduction in flexibility that any individual NSP might exercise.

Commission considerations

The Commission believes the requirement for an access undertaking provides Code participants with transparency and certainty as to the obligations of NSPs. The fact that the Code consultation procedures are to be used to draw up guidelines for exemptions from having to provide an undertaking also provides transparency. Overall, the Commission considers that these clauses provide a net public benefit.

10.3 Connection

Clause 5.3 and Schedules 5.4–5.6 set out detailed procedures for a party seeking to establish or modify connection to a network and for NSPs to process connection applications. The procedures encompass the enquiry to the NSP, the response to the enquiry, the application, the response to the application and the offer to connect. Obligations are placed on the parties (including the type of information required), strict timelines apply and there are limitations on the use of information.

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[79] See also clause 2.6(b).

Issues for the Commission

The Code's connection arrangements may restrict participation if they are too onerous or costly. In addition, there may be anti-competitive outcomes when negotiating with a monopoly NSP.

The applicants state that, clause 5.3.7 (which provides that a Connection Applicant who wishes to accept an offer to connect made by an NSP must agree to be bound by the relevant provisions of the Code) could be considered to have the purpose or effect of substantially lessening competition.

What the interested parties say

EUG, Boral Energy and SMHEA are concerned with the unequal bargaining power between monopoly NSPs and connection applicants. The EUG believes that the Code's approach to connection could prove to be onerous and costly to parties seeking access and that this could increase charges to end-users or limit upstream and downstream competition.

The Victorian DBs argue that the current connection requirements are inappropriate for all distribution connections and the Code should be amended to allow NSPs discretion in applying Code procedures or set a threshold compliance level.

The EUG, SMHEA, ACM, Boral Energy and ACCI argue strongly that bypass should be expressly provided for in the Code. The EUG and Australian Paper suggest that bypass is an alternative to 'negotiation' with a monopoly supplier. In particular, the EUG states that this provides for much more effective negotiations on access by allowing the network user to apply a threat of competitive bypass where access charges are exorbitant, where onerous terms and conditions are being imposed or where negotiations are being thwarted by the NSP. They note that such a right is a feature of the gas regime being proposed and has been endorsed by IPART.

The EUG contends that the prime motive to not codifying bypass is to protect stranded costs and restrict competition and strongly objects to being asked to bear the costs of such (hidden) restrictions on competition.

What the applicants say

The applicants state that the connection provisions have been developed based on the principle of commercial negotiation of connection services, terms and charges. This regime, they argue, is synonymous with the concept of light handed regulation. The applicants contend that the principal intention of the Code's connection arrangements is to limit the ability of NSPs to use their natural monopoly power to the detriment of network users and provide adequate levels of services to network users.

With respect to bypass, the applicants further state that the Code neither encourages nor discourages bypass; it simply permits it. They say the Code seeks to ensure that the transmission pricing and regulatory arrangements do not unduly encourage new investment in facilities which substitute for or duplicate existing facilities, where the incremental costs of the new facilities are greater than the avoided incremental costs of existing facilities. This approach, they say, is intended to ensure that bypass of existing networks only occurs where bypass is in the public interest (i.e. where bypass is the least-cost option from a total societal perspective). The applicants consider it unnecessary for the Code to explicitly mandate bypass.

Issues arising from the draft determination

Nearly all submissions at the pre-decision conference and afterwards support an express provision allowing bypass by third parties of existing network. However, opinions differed as to whether the implementation of bypass should be subject to any efficiency or similar criteria.

Network service providers and others[80] voice concerns about the Code allowing for inefficient bypass and duplication of assets. In particular, they emphasise that:

- the incentive for bypass is created by distortions in network pricing, especially where averaging and maximum tariffs result in prices that are not cost-reflective;
- providers, particularly distributors who are obliged to maintain averaging, cross-subsidies and maximum tariffs, will find it very difficult to accommodate significant bypass within these pricing restraints;
- even outside such restraints, bypass could result in the remaining network customers paying more to prevent the stranding of existing assets;
- users exercising a right to bypass should still contribute to subsidies within the network pricing arrangements;
- bypass to non-contestable customers should not be allowed to undermine agreed transition arrangements; and
- third parties who bypass the network should register under the Code as network service providers and be required to provide an access undertaking.

Customers and user groups[81] support an explicit provision allowing bypass, seeing it as a countervailing factor in negotiations with monopoly network service providers. They express concern about conditions or guidelines governing the implementation of bypass that may have the effect of unduly restricting its use. They propose that either:

- there be no restrictions on the negotiation of bypass arrangements apart from commercial incentives and reasonable technical conditions; or
- that any guidelines focus on procedures for the efficient negotiation and implementation of bypass, leaving it to the investors to judge whether or not bypass is economically efficient.

Dr Hugh Outhred notes that it would be unwise to rely too heavily on bypass to control NSP behaviour.

A related issue raised by network users was the scope of both rights of access and bypass under the Code, with particular focus on access to easements. At the pre-decision conference TransGrid indicated that easements were not part of the Code because they are covered by jurisdictional laws. Cadia Mines advocate that rights of access, including procedures for

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80 TransGrid; Solaris; CitiPower; Eastern Energy; Powercor; SEQEB; Incumbent New South Wales DNSPs; South Australian Government; SMHEA; energyAustralia.

81 EUG; BCA; ACA; BHP; Australian Paper; Cadia Mines; Ampol.

resumption and compensation of freehold, should be the same as for statutory bodies. The EUG requests that, before approving the Code, the Commission ensures that the exclusion of easements from the National Electricity Code will not diminish contestability.

The applicants state that they will propose a Code amendment along the lines of the express provision for bypass in the access arrangements for gas. The applicants also agree that the review of transmission and distribution pricing will include a more detailed consideration of bypass, including the issue of efficient bypass, and will consider the content of guidelines.

Commission considerations

Detailed discussion and analysis of connection can be found in section 4.2 of the *NEM Access Code Draft Determination. A* summary of the discussion follows.

In general the Commission considers that the connection negotiation process promotes the interest of facility owners and network users in that it:

- gives appropriate emphasis to the customer exercising their initiative to establish access to the network;
- documents in detail the procedures, standards and information required to negotiate a connection agreement;
- employs time lines and other obligations to ensure connection negotiations progress to a suitable outcome; and
- allows for review of critical decisions affecting participants' interests.

Despite this, the Commission shares a number of the interested parties concerns in relation to the relative negotiating position of NSPs and access seekers, and the information burdens the Code's connection procedures place on smaller access seekers. The Commission recommends that the connection procedures set out in the Code be assessed and their appropriateness for smaller connection applicants be considered.

The Commission also believes that it will be in the interests of access seekers if the Code included an explicit right for users to bypass networks.

Submissions advocate a right to bypass as a means of disciplining the power of monopoly NSPs and an opportunity for contestable entry into both the provision of network services and participation in the market. The Commission agrees that without an explicit right to bypass a network, access seekers have very little bargaining power in negotiating with a network monopoly and the NSP could be viewed as possessing an exclusive franchise. This is inconsistent with the Code's principles of contestable network facilities and with the bypass arrangements for gas pipelines in the proposed national gas code arrangements.

In light of these considerations, the Commission believes NECA must include in the Code an explicit right for users to bypass electricity networks. However, more work is needed to explain how bypass will work in practice, how it will mesh with other aspects of the Code and how it will account for the interests of users, providers and the public. Consequently, to ensure that these arrangements are efficient and do not adversely impact on inter-connected networks and users, the Code should allow for the development of guidelines to govern the bypass arrangements. This is a matter that will now be taken up in the context of the NECA review of network pricing.

The views expressed at the pre-decision conference and in subsequent submissions reinforce the Commission's view that the Code should expressly allow for bypass. In this context, the Commission is conscious that transmission and distribution networks have the capacity to deliver a range of services apart from the transport of electrical energy. With regard to access and bypass, the Code needs to clearly define that the network services it governs are solely those services associated with the conveyance and control of electricity through the network.

In addition, the concerns raised by both users and providers regarding implementation of bypass within the context of existing regulatory arrangements support the Commission's view that guidelines on bypass are required. These arrangements presently cover such diverse issues as regulated tariffs, cross-subsidies and statutory easements. Given the complexity of these issues, such guidelines should aim to accommodate the diverse interests of facility owners, network users and final consumers by:

- setting out effective negotiation and implementation procedures;
- defining conditions for efficient investment in bypass within evolving network pricing arrangements;
- clarifying the status of bypass facilities with regard to access undertakings and jurisdictional planning laws.

The Commission supports the applicants' proposal to develop such guidelines in conjunction with the review of network pricing.

Condition of authorisation

C10.1 The Code must be amended to explicitly recognise the right of third parties to bypass the network.

10.4 Access arrangements for generators

Clause 5.5 provides for additional arrangements for generators to gain access to the network. This clause provides for the negotiation of firm access.[82]

Issues for the Commission

The access arrangements could give rise to anti-competitive detriment as negotiation with a monopoly NSP may be difficult and as incumbent generators may dominate the arrangements to the exclusion of new entrants.

What the interested parties say

Macquarie Generation, SMHEA, Yallourn Energy and Hazelwood Power all request an explicit obligation on NSPs to offer firm access to network availability.

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82 Firm access in this case means an intra-regional hedge which insures against the risk of network constraints within a region preventing generators (or customers) from taking advantage of favourable spot prices. In other words, the hedge works as a proxy for continued access to the regional spot price at traded volumes.

Ecogen Energy is concerned that given the monopoly position of NSPs, generators will be unable to negotiate a commercially reasonable price.

The Tasmanian Government contends that firm access arrangements should be applied to both loads and generation and also to interconnection projects to ensure that there is no bias between generation, interconnections or load management options. Furthermore, it and SMHEA believe that there are merits in examining whether firm access contracts should be settled in the same way as IRH contracts as this would simplify the pricing arrangements between NSPs and market participants and provide appropriate signals for transmission augmentation.

Greenpeace argues that the use of firm access transmission contracts would appear to significantly improve the way in which the cost of network service provision reflects constraints. It believes that if these were broadly applied throughout the network, the opportunities for distributed generation or demand management to compete with network augmentation would be more apparent.

What the applicants say

The applicants note that compensation obligations are not imposed upon NSPs by the Code with respect to customer connection or other NSP connection arrangements. However, the Code does not preclude such compensation arrangements being negotiated between NSPs and customers and other NSPs.

The applicants contend that the compensation provisions of clause 5.5(f) enables the generator and the NSP to come to an appropriate risk sharing arrangement given that the generator should have been dispatched and may be exposed to financial losses under a contract for differences.

They submit that this arrangement provides a public benefit because energy customers and generators are provided with incentives to behave in an appropriate manner to maintain a secure power system at the same time as they are provided with economic signals to which they can sensibly respond.

Issues arising from the draft determination

At the pre-decision conference and in subsequent submissions,[83] generators argue for a significant strengthening of the firm access provisions in clause 5.5. They request that network service providers be obliged under the Code to negotiate and offer firm access hedge arrangements with compensation whenever generators are constrained-off the network. They argue that, under the present provisions, network service providers presently negotiate from a monopoly position and thus have no incentive to bear extra risk of network constraints and the adverse impact these constraints can have on access to favourable pool prices. The incumbent generators argue that network service providers should offer a choice of access arrangements including, but not restricted to, firm access. They also argue that obliging network service providers to offer firm access would be the most efficient allocation of network risks to the party most able to bear the risks and would reinforce locational pricing on different parts of the network, thus removing uncertainty for new generators connecting to the network.

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[83] Yallourn Energy; Optima Energy; Macquarie Generation; Loy Yang Power; Hazelwood; SMHEA.

At the pre-decision conference the ACA commented that generators would be entitled to firm access if they paid for it, referring to the fact that generators (in contrast to loads and embedded generation) are currently not liable for transmission charges. Submissions from user groups and customers[84] propose that generators should pay TUOS charges and negotiate firm access in their connection agreements with their network service providers. The ACA argues this will create commercial incentives for generators to monitor, and providers to improve, network performance. It also argues that the exemption of generators from network pricing means users and consumers will ultimately bear the capital cost of transmission.

A number of these submissions indicated that firm access is linked to the resolution of several other issues, including the structure and incidence of TUOS prices, commercial arrangements for ancillary services and system security, payment for constrained-on generation and network augmentation.

NECA indicated that firm access is one of the issues identified for inclusion in its review of transmission and distribution pricing.

Commission considerations

A full discussion of the Commission's analysis of the access arrangements for generators can be found in section 4.2 of the *NEM Access Code Draft Determination*. A summary of the discussion follows.

The Commission considers that commercial incentives and the Code arrangements provide the opportunity for negotiation of firm access and other access arrangements by generators. Firm access should provide public benefit by allowing for greater certainty and identifying and valuing network constraints such that the network may be enhanced as required. The Commission's *NEM Access Code Draft Determination* recommends that at an appropriate time after commencement of the market, NECA should review the arrangements for firm access so the CCP can consider any amendments required to introduce further incentives and/or obligations regarding the provision of firm access.

Submissions received since the pre-decision conference indicate that firm access is a complex issue which cannot be dealt with in isolation. It has ramifications for other concerns such as the identification and management of network constraints, the potential to commercialise ancillary services, compensation for both constrained-on and constrained-off generation, the scope for generators to pay transmission charges and the obligations and incentives on network service providers to deliver identifiable standards of service.

In the light of these submissions the Commission supports the NECA proposal of a full consideration of the issues surrounding firm access in the review of transmission and distribution pricing, including the allocation of transmission charges, the management of network risks and constraints and the development of commercial arrangements for ancillary services.

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84 ACA; EUG; BCA; Ampol; Incumbent New South Wales DSNPs; energyAustralia; Australian Paper.

10.5 Network augmentation and planning

Clause 5.6 of the Code concerns network planning and development. In particular, clauses 5.6.1 and 5.6.2 deal with intra-regional network planning and development by NSPs (annual reviews, etc.) and Schedule 5.7 sets out the information that must be provided to the NSP by generators and market customers.

Issues for the Commission

The Commission is concerned with the extent to which the provisions may be arrangements which protect NSPs and other network users from potential externalities, create a barrier to market entry, and limit contestability of network augmentation. All of these may limit competition for augmentation and may increase costs to network users. In addition there may be elements of exclusive dealing in that the planning design approval must be done by NSPs.

What the interested parties say

Issues raised in submissions in relation to network augmentation and planning can be placed into one of the three following categories:

- representation on and consultation by the IRPC;
- issues regarding planning and co-ordination; contestability in augmentation and evaluation; and
- interconnector arrangements.

Representation and consultation

The EUG, Dr Hugh Outhred, the NFF, the Tasmanian Government and Environment Australia all argue that additional interests need to be represented on the IRPC.

The Victorian DBs, VPX and Greenpeace raise conflict of interest concerns in relation to the composition of the IRPC. For instance, the Victorian DBs suggest that conflicts of interest could arise because the IRPC is likely to include persons from businesses that are directly affected by the IRPC's decisions. In addition, the Victorian DBs note that members of the IRPC are likely to have access to commercially sensitive information regarding the market position of all market participants.

Planning and co-ordination

The EUG would prefer that network planning decisions be devolved to market participants, but accepts that a degree of central co-ordination is inevitable given that the NEM must, to some extent, be run as a single system.

TransGrid is concerned with the planning process and the impact on network use of system prices in that, by advantaging one customer, it is possible to disadvantage another, and achieving consensus among many participants will be difficult.

VPX believes that arrangements should include a clear definition of stranded asset risk allocation as between network owners and network users, in situations where network investments are evaluated and approved by a central agency such as NEMMCO.

Contestability in augmentation and evaluation

The EUG believes that the Code as presently drafted does not give sufficient weight to other possible ways in which competition may be enhanced and augmentation made more efficient and argues that assessment needs to be made of whether these matters justify the proposed approach to augmentation.

VPX argues that arrangements should provide maximum scope for the introduction of competition for design, construction, ownership and management of assets in the transmission sector.

Greenpeace contends that the precise basis of network planning decisions is unclear — specifically the extent to which NSPs will be required to include the potential for energy efficiency and distributed resources as an alternative to network augmentation.

TransGrid believes that network augmentation options should take account of community concerns and environmental impacts.

Interconnectors

The South Australian Government has concerns about the provisions in clause 5.6 of the Code with respect to the arrangements for assessing potential new interconnections and the role of NEMMCO in decision making.

The Tasmanian Government is concerned that arrangements for non-regulated interconnections are undefined in the Code and argues that this may discourage new entrants from putting forward these types of projects. SMHEA believes that the Code should provide a proper framework for entrepreneurial interconnectors. It argues that proposals should be developed as soon as possible and be incorporated into the Code.

What the applicants say

The applicants argue that the co-operation between monopoly service providers (within the IRPC) is essential to properly plan and enable expansion of the power system's transmission networks to provide transmission services to new generators and customers seeking access. In the absence of a co-ordinated transmission planning process, the quality of supply to existing and new network users cannot be maintained.

The applicants submit that the network planning arrangements provide a public benefit as they:

- provide for an objective review of the net benefit of the proposed investment to be undertaken by an independent party which has no commercial interest in the outcome;
- provide for all parties affected by the proposed investment to have input into a comprehensive and transparent review process prior to any investment decision being made;
- provide for a further independent review by the National Electricity Tribunal of NEMMCO's determination if a party wishes the decision to be reviewed; and

- seek to ensure that where the IRPC's process leads to a determination that the augmentation is of net benefit to customers, the network owner does not unduly bear risk associated with an investment made as a result of that process.

The applicants submit that the Code effectively balances the interests of different parties in its treatment of network augmentation. It recognises the economies of central information collection and network planning, and attributes the risk of stranded assets to those parties who make the investment decision (or, in the case of customers as a whole, on whose behalf the decision is made). They argue that the proposed national approach to transmission planning via NEMMCO will help to ensure that access to both upstream and downstream markets via transmission networks is assessed consistently from a national rather than a regional perspective.

Issues arising from the draft determination

TransGrid questions whether conditions C10.3 and C10.5 gave undue emphasis to generation and demand side options at the expense of other issues, such as scrutiny of market power and pool price behaviour. The EUG disagrees with TransGrid and states that new generation and demand side options are physical alternatives to network investment that the IRPC and NEMMCO should consider, whereas competitive market structure and pricing are economic objectives underlying the network planning and review process. SEQEB also supports the consideration of generation and demand side options.

In its submission TransGrid states that the Commission's concerns regarding alternatives to augmentation are already addressed in the Code and should be left open to allow NEMMCO to consider a range of matters, including the duration and severity of constraints, pool prices, market power, consequential transmission augmentations, or the relative prices or greenhouse impacts of alternative fuels. It notes that interconnection decisions will need to consider long-term effects across relevant regions and that the IRPC will have no power to implement generation or demand-side options.

Australian Paper state that it considers the Code should require information to be disclosed to allow a review of NSP costs and new infrastructure projects.

The applicants state, in response to the Commission's conditions, that appropriate amendments will be made to the Code covering the composition and role of the IRPC.

Commission considerations

Detailed discussion of the Commission's analysis of the network augmentation proposals is contained in section 5 of the *NEM Access Code Draft Determination*. A summary of the discussion follows.

New/modified connection

The Commission believes that the requirements of Chapter 5 reduce potential barriers to entry by obliging monopoly NSPs to augment networks to facilitate the connection of new participants with whom they have reached a connection agreement.

However, the Commission believes that the interests of network users and access seekers would be further promoted if the Code included additional incentives to ensure that network augmentation is undertaken at least cost. To a limited extent, this is already an option as NSPs can choose embedded generation options over network augmentation and they can choose to contract out the building or planning of an augmentation. Despite these cost pressures, more broad contestability of network augmentation to facilitate a new connection, should allow the party seeking connection to choose who will provide the augmentation and may include retaining ownership of the augmented assets. It still remains that the relevant NSP would have control over the technical aspects of any connection into its network and as such will still be involved in the planning and testing of the augmentation.

The contestability of augmentation is an extension of the network bypass option which, as was discussed in the previous section, places yet another pressure on NSPs to minimise the cost of network connection. At present the Code does not mention bypass, and the Commission's desire to see a positive endorsement of bypass as an option is consistent with the Commission's desire that network augmentations be fully contestable.

Intra-regional network planning

The Code as it relates to the requirement on NSPs to undertake a review of its network in a co-ordinated fashion with other NSPs is in the public interest and is accepted by the Commission. As the public process that is to follow the identification of augmentation options is transparent and inclusive the Commission accepts it as part of the Code.

Information requirements

The Commission believes it is reasonable that NSPs are not responsible for any adverse consequences if they fail to modify forecast information supplied to them because they may not be in a position to determine its accuracy. However, there is concern that if NSPs do choose to modify forecasts and they are not responsible for the consequences, this could allow NSPs to inflate the estimated demands on the network so as to allow over-investment in the network. Alternatively, NSPs could lower forecast demands on the network to increase constraints on the network and allow them to increase use of system charges. These outcomes amount to an anti-competitive detriment due to inflated use of system charges.

The Commission is of the view that there should be guidelines governing how and why NSPs are able to modify forecasts. This would assist in resolving any dispute over alterations to forecasts and establish grounds upon which Code participants could dispute modifications.

The Commission supports full information disclosure, except where commercial confidentiality is requested and recommends the Code be amended, if necessary, to enable public review of information regarding NSP costs and new infrastructure projects.

Inter-regional Planning Committee

As with all of the Code's administrative bodies, independent membership of the IRPC is important to ensure that no single interest is favoured over another. At the same time, the members of the IRPC should possess technical expertise to ensure they provide competent advice on system wide augmentation. The Commission recognises there may be only a limited field of people who are willing to be an IRPC member, are technically competent and can objectively participate in the IRPC's deliberations.

The Code requires the members of the IRPC be appointed by NEMMCO and by jurisdictional Ministers. While the jurisdictional nominees will come from organisations responsible for transmission system planning, the ability of NSPs to unduly bias the determinations of the IRPC is constrained by the appointment mechanism. Consequently, it is NEMMCO's and the jurisdictional Ministers' responsibility to ensure that their nominees fulfil their duties in an independent and technically competent manner. In arriving at this conclusion, the Commission attaches particular significance to the fact that all transmission system planning bodies are publicly owned and therefore they, and their employees, are subject to performing their duties in a way which is, at least, consistent with the public interest.

Nevertheless, the Commission notes that this link may be weakened at some point in the future given the recent trend towards the privatisation of publicly owned bodies. In the event that further NSPs are privatised and that system planning responsibilities are retained within the privatised NSP, the Commission shares participants' concerns regarding the likelihood that members of the IRPC will act in the commercial interests of NSPs and not in the broader public interest.

One option suggested by participants was to separate the network planning functions from the network operation functions. While this approach has some appeal, issues relating to the structural reform of NSPs are beyond the scope of this review and are the responsibility of the jurisdictional governments. Nevertheless, the Commission believes that, in the circumstances described, participants have raised legitimate concerns about the membership of the IRPC. Consequently, the Commission believes that the Code should provide scope for jurisdictional nominees to come from outside a transmission network planning organisation in the event that a conflict of interest is apparent.

Apart from its membership, an equally important determinant in the quality of the IRPC's recommendations is its ability to draw on the perspectives of, and information from, interested parties. Consistent with this objective, the IRPC is required to consult widely and give consideration to a range of alternatives to augmentation. The IRPC review process is a transparent and accountable process as it is required to listen and consider all views and obtain a decision based on a 'net economic benefit test'. The requirement to include the methodology it has used in coming to a decision greatly increases the accountability of the process.

Consequently, the Commission believes the Code requirement that the IRPC conduct its deliberations in a transparent and accountable manner is in the public interest. Nevertheless, the IRPC's process could be improved by requiring it to develop guidelines on how it will conduct its public consultations. Moreover, the IRPC should have the ability to indicate the relative merits of network augmentation vis a vis generation or demand side options. This would provide a clear signal to the market for commercial opportunities which may otherwise be excluded as a viable option or dominated by the NSPs.

In response to the TransGrid comments, the Commission's conditions are not intended to limit the considerations of the IRPC or NEMMCO to the likelihood of generation and demand-side options but to make these factors explicit in their evaluation of likely viable solutions to inter-regional constraints. The IRPC and/or NEMMCO would be equally entitled to examine the other issues as raised by TransGrid.

In assessing network augmentation options, the role played by the IRPC is spelt out in the Code while NEMMCO's role is less clear. Its responsibility, for releasing the statement of opportunities has merit given its role and status in the NEM. The statement of opportunities report raises concerns in that NEMMCO, unlike the IRPC, is not required to look at alternatives to transmission options such as generation and/or demand management. Thus the Code places no requirement on NEMMCO to obtain a least cost solution, instead it is to look at what option maximises net benefits to customers. The Code's definition of customers refers to persons that register with NEMMCO as customers and hence maximising the net benefits to customers criteria may not be consistent with maximising the overall public benefit.

Additionally the applicant has suggested that the decision of NEMMCO will protect network providers from risk of the new asset becoming stranded. While such an arrangement has merit, it should be noted that this claim is not entirely consistent with provisions of Chapter 6 (network pricing) of the Code. For instance, Chapter 6 of the Code gives strong guidance to the regulator to value assets in a manner which is consistent with a NEMMCO determination. However, the Code provides the regulator with some degree of flexibility to value assets on some other basis.

Interconnectors

Interconnectors provide the opportunity for greater competition in each region by increasing the available capacity of generation. The Commission believes that the Code contains no unnecessary barriers to entry against new interconnections. The Code includes assessment procedures whereby a facility owner can establish an interconnection where there are demonstrable benefits. Further, a business may establish an interconnection irrespective of the views of the IRPC and NEMMCO, although in that case it will have to contribute to the necessary system augmentations and will not be guaranteed a return on its investment.

Conditions of authorisation

C10.2 Clause 5.6.3(b) must be amended to provide that the representative from the nominated jurisdictional entity must not be involved with any decision of the IRPC where a conflict of interest between the commercial operation of the entity they represent and the decision of the IRPC may arise.

C10.3 Clause 5.6.5 must be amended to require the Inter-regional Planning Committee to include in its report to NEMMCO consideration of alternative strategies to network augmentation for removing or reducing network constraints.

C10.4 Clause 5.6.5 must be amended to provide that the Inter-regional Planning Committee conduct its public review processes in accordance with the Code consultation procedures.

C10.5 Clause 5.6.5(k) must be amended to provide that, in arriving at its determination under clause 5.6.5(j), NEMMCO must also consider alternatives to network augmentation including, but not limited to, alternative generation and demand side options.

10.6 Inspection, testing and commissioning requirements

Clauses 5.7 and 5.8 cover inspection and testing to ensure that connected equipment complies with the specified performance criteria. These arrangements create rights to enter establishments and conduct tests on existing systems and equipment, and conduct commissioning tests on new or replacement equipment.

Issues for the Commission

Provisions which give participants the right to inspect another participant's premises and equipment have the potential to be misused for anti-competitive purposes.

The costs of inspection and testing could be anti-competitive if onerous.

What the interested parties say

Mr Chek Ling argues that the Code inappropriately stipulates that the NSP should conduct system testing. He claims that the system operator would be the more appropriate organisation to conduct system testing.

The consultant's view

Western Power recognises that the right to enter another's facilities to check a possible breach of the Code or connection agreement is an effective way to encourage all participants to take an active interest in the power system and to sort problems out between themselves rather than the alternative of NEMMCO or the NSP intervening each time.

However, Western Power warns this could be open to abuse, notwithstanding that there is a connection agreement, particularly if the parties are competitors (such as in the case of interconnected NSPs) and given that only two days' notice is required. It suggests a longer period as more appropriate unless the problem requires urgent attention. Overall, it concludes that it would appear to be more appropriate to have either the NSP, NEMMCO or NECA investigate alleged breaches of the Code or a connection agreement.

Western Power considers that the commissioning requirements are reasonable and would generally be in accordance with accepted industry practice. The only concern relates to the fact that the IRPC has the final say on control and protection settings for equipment. It argues that, given the IRPC is not independent, it is possible for a conflict of interest to occur and it may be better to have the settings reviewed by an independent expert.

Issues arising from the draft determination

TransGrid and the New South Wales distribution businesses submit, with regard to inspection rights, that the intent of the Code was to provide reciprocal rights in a connection agreement as an improvement on the unilateral network service provider rights which currently exist. They also point out that such rights are likely to be exercised in respect of suspected Code breaches or in response to consumers' complaints about the quality of supply. In either case the NSP would have to be involved in the inspection to investigate the problem.

TransGrid does not support the draft determination condition that the Code's dispute resolution processes should be available to a participant objecting to the inspection or testing of its facilities by another participant. TransGrid states that the dispute resolution process has no legal basis for resolving such disputes and could cause considerable delay which might subvert the purpose of the inspection or testing.

TransGrid also recommends that the annual review of inspection rights be carried by NECA rather than NEMMCO, as it has more to do with Code effectiveness than market operation.

NECA indicated that appropriate amendments to the Code will be brought forward to meet the Commission's concerns in relation to inspection rights.

Commission considerations

A full discussion of the Commission's considerations is to be found in section 4.4 of the *NEM Access Code Draft Determination*. A summary of the discussion follows.

The Commission is concerned that the right to inspect another's premises and equipment may be misused for anti-competitive purposes rather than Code objectives. Such rights, particularly between competitors (e.g. two interconnected NSPs), rarely exist in other markets. They carry with them some risk of conflicts of interest, market interference and even the potential for industrial espionage. Moreover, the Code does not allow a participant to object or appeal once notified of an impending inspection.

One way of minimising these potential conflicts of interest is to move the inspection function from the hands of participants to an independent body such as NEMMCO or NECA. The benefit of this would be to establish a system of inspection seen to be impartial and whose authority to make binding decisions is accepted by participants. Also, the actions and decisions of an inspectorate might be more open to public scrutiny through accountability and monitoring arrangements.

However, it would be costly to establish and maintain a separate inspectorate. Moreover, an inspectorate's activities may be limited by both insufficient resources and information problems. It could also deprive participants of initiative and responsibility in managing their own affairs while creating an extra layer of bureaucracy within the industry.

It is apparent that both the present system for spot inspections and the alternative of a separate inspectorate have costs and benefits, and a decision in favour of one or the other will involve a trade-off between these factors.

However, the Commission appreciates that the rights in clause 5.7 are an improvement on existing inspection rights and have been designed with several safeguards in place to meet the concerns of bias and potential for abuse. It is recommended that the effectiveness (or otherwise) of these safeguards should be tested, after an appropriate period of time, by NECA based on the experience of participants in the market to see whether they are achieving their stated objectives without detriment to access or competition. Hence existing Code provisions regarding inspection and testing need to be strictly limited and audited after a suitable period of use. In the light TransGrid's comments and after reconsideration of the issues, the Commission considers it would be appropriate that the use of dispute resolution procedures be considered in the context of that review process and thus has decided not to impose a condition at this time.

Conditions of authorisation

C10.6 Clauses 5.7.1 and 5.7.2 must be amended to provide that reports of tests and inspections are to be made available to the Code participant whose facilities are being inspected or tested, the Code participant requiring the test or inspection, NEMMCO and any other person who may be affected by the results of the test or inspection.

C10.7 Clauses 5.7.1 and 5.7.2 must be amended to provide that NECA must annually prepare a report detailing the use of inspection and testing rights by all Code participants. The report must be completed within 30 days of each anniversary

of the NEM commencement in respect of the preceding year and must be made available to all Code participants and interested persons.

10.7 Disconnection and reconnection

The Code provides for either voluntary or involuntary disconnection from the network. The procedures are set out in the Code which must be followed in both events. The Code also sets out the conditions for reconnection.

Issues for the Commission

The Commission is concerned that the costs of disconnection and decommissioning of equipment could constitute barriers to exit from the market, over and above that necessary to ensure system security. Also, there is the possibility that the NSP, as final arbiter on what is necessary in these circumstances, could impose undue burdens on Code participants.

In relation to involuntary disconnection, the Commission wishes to ensure that these procedures are fair and that costs are borne by the most relevant parties in the particular circumstances so that any anti-competitive detriment is minimised. Also relevant is whether procedures for review of actions taken are adequate to protect the interests of Code participants.

What the interested parties say

SEQEB is concerned with how the costs of voluntary disconnection and decommissioning are to be determined and as to who arbitrates on the equity of their application.

The consultant's view

Western Power states that the disconnection processes appear to be reasonable to protect the interests of NSPs and Code participants. It believes that the list of circumstances given in clause 5.9.3(a) which allow an NSP or NEMMCO to disconnect a Code participant should adequately protect the interests of Code participants. It contends that a Code participant should only have to pay for reconnection if it was in some way responsible for the disconnection in the first place.

Western Power also suggests that it would assist participants if, consistent with the NEL, the Code explained the circumstances under which an NSP or NEMMCO can disconnect a participant. However, it notes that a disadvantage of this approach is the need to ensure that the Code is updated if there has been a change in the law.

Issues arising from the draft determination

The draft determination reiterated the Commission's draft access recommendations that:

- the Code include a clear statement of intent that involuntary disconnection will be used as a last resort;
- the Code more clearly specify the process, rights and obligations of participants and service providers regarding disconnection and rectify the inconsistencies between the various Code provisions and between the Code and the National Electricity Law;

- continued payment for services by disconnected participants be limited to outstanding debts and other liabilities incurred under the connection agreement; and
- participants only pay to be reconnected if they were responsible for the disconnection through failure to follow the Code or connection agreement.

TransGrid supported the statement of intent but pointed out that disconnection for emergency conditions is a NEMMCO responsibility rather than a network connection issue and that disconnection can occur without warning (eg due cascading failures). It also supported a clarification of the disconnection procedures but noted this is a complex issue involving jurisdictional legislation covering distribution networks.

TransGrid did not support amendment of the ‘continued payment for services’ provision until the NECA review is finalised. It stated the intent is to remove the risk of a participant avoiding payment for services provided during the disconnection period (covered by a fixed charge) which cause a financial loss to the network service provider. Also on this issue, CitiPower commented that it is a fundamental right to cease supply of a product or service if the consumer does not meet obligations and that ‘connection agreement’ in this context should also cover energy consumed and related services.

In relation to reconnection, CitiPower stated that if a previous customer has requested disconnection, it does not seem unreasonable that the incoming customer pay for reconnection if this is required.

The applicants indicate that NECA will review the arrangements for disconnection under the National Electricity Law and the Code and will publish a report, including recommendations for amendments to the National Electricity Law and the Code as necessary. They state that the review will need to reconcile the powers under the National Electricity Law and the Code with related obligations under jurisdictional legislation, in particular in relation to ensuring continuity of supply to end-use customers.

Commission considerations

A full discussion of the Commission’s considerations is to be found in section 4.5 of the *NEM Access Code Draft Determination*. A summary of the discussion follows.

Complexity of procedures

The design of the procedures for involuntary disconnection makes them hard to follow, something also noted by Western Power. In addition Western Power identifies a number of inconsistencies between the Code and the NEL which could thwart the original intentions and compromise the interests of both users and providers. Because of this lack of clarity, participants may be at a disadvantage in understanding and using their rights and obligations when faced with the prospect of disconnection. At the same time Code bodies or NSPs may be tempted to abuse their information advantage in order to expedite matters or secure a particular result. In both circumstances the principles of natural justice and due process may suffer.

Disconnection is an extreme measure but in some circumstances it will be warranted. The Code needs to operate clearly and effectively in defining those circumstances and the procedures to be followed. At the same time the Code also needs to identify those cases where disconnection is not an option and what alternatives there are to dealing with the Code breach or problem in question. An improved explanation of the use of disconnection as a Code remedy is needed to clarify the present uncertainty and complexity.

The Commission's *NEM Access Code Draft Determination* therefore recommends that the Code include a clear statement of intent that involuntary disconnection will be used as a last resort. The Commission's *NEM Access Code Draft Determination* also recommends that the Code specify more clearly the process, rights and obligations of participants and service providers regarding disconnection and rectify the inconsistencies between the various Code provisions and between the Code and the NEL. Finally it is recommended that the Code specify which Code breaches and market defaults will lead to disconnection, consistent with penalties in the regulations.

Continued payment for services

The Commission questions why participants disconnected as a result of a Tribunal order should continue paying for services they do not receive 'as if disconnection had not occurred' (see clause 5.9.4(c)). Disconnection (and subsequent reconnection) itself imposes financial loss and inconvenience on the affected participant. Hence it is unclear why an additional penalty or disincentive should always apply nor why it applies only to disconnections ordered by the Tribunal.

The Commission is aware that some connection agreements may involve connection and network charges being spread over time, such that the participant is liable in the future for benefits received now. This can occur where the NSP has invested new capital for the purpose of connecting the participant and will not recoup these costs if the participant is disconnected and does not meet future liabilities. Similarly, the NSP has a right to recover outstanding debts up to the moment of disconnection. If these are the cases where clause 5.9.4(c) applies, it would be better if it were rewritten to oblige disconnected participants to meet those present and future charges for which they are liable under the connection agreement or market arrangements. To ensure that the Code has sufficient accountability and flexibility in regard to such payments, actions taken to enforce this obligation should be reviewable decisions.

The Commission accepts TransGrid's point that fixed charges may continue to apply during a disconnection period and CitiPower's point that energy and related liabilities may also be involved. The Commission's intent is that such liabilities (for either network services or energy) be made explicit in the Code and/or connection agreement rather than rely on a general obligation to pay for services 'as if disconnection had not occurred.'

The Commission's *NEM Access Code Draft Determination* recommends that the Code's obligation that a disconnected participant continue paying for services if disconnection has occurred be limited to payment of debts and other liabilities incurred under the connection agreement or market arrangements.

Payment for reconnection

The Commission also questions whether disconnected participants should pay for reconnection (see clause 5.9.6) when they are not at fault, even if it is 'at a reasonable cost.' Where the participant's actions or omissions have contributed to or caused the disconnection, the relevant NSP should be paid for reconnection. However, where the participant has complied with the Code, making him or her pay for reconnection most likely transfers someone else's liability to that participant without justification. Elsewhere the Code indemnifies the actions of NEMMCO or an NSP that are made in good faith. Clause 5.9.6 seems to contradict this by making the participant pay whatever the circumstances.

It would be more acceptable to restrict this condition to those occasions when the same participant is responsible for the disconnection. As with the continued payment of network charges, to ensure accountability and flexibility the obligation on individual participants to pay for reconnection should be reviewable by the Tribunal.

It also accepts CitiPower's point concerning reconnection of a site where there is a change of customer. In such circumstances it is reasonable that the new customer pays to reconnect the site. The Commission's concerns focused on cases of involuntary disconnection and reconnection of the same customer at the same site.

The Commission's *NEM Access Code Draft Determination* recommends that participants pay for reconnection only if they were responsible through failure to follow the Code or connection agreement, for the disconnection. It is recommended that action taken in relation to disconnections not ordered by the Tribunal and to reconnections should be classified as reviewable decisions under the Code and the NEL.

The Commission considers that the proposed review of disconnection provisions will be a useful means to identify, clarify and, where necessary, amend the operation and interaction of the National Electricity Law, the code and jurisdictional laws in this area.

11. Network pricing

Chapter 6 of the Code establishes separate regimes for pricing transmission and distribution networks whereby government appointed regulators will determine asset values, rates of return, and revenue and/or price caps. To this end, the Code outlines principle objectives and cost allocation procedures to guide NSPs and regulators. The Code provides for a review by NECA of the pricing methodologies and principles used by government regulators to be completed by 1 January 1999.

Issue for the Commission

An effective access regime is essential to the realisation, and pass through, of the benefits of upstream and downstream competition. Effective network pricing and regulation proposals should be designed to:

- prevent monopoly rent taking by transmission network owners; and
- provide effective price signals for the use of existing network facilities and for future investment in the network.

To the extent that network pricing does not provide the right price signals and incentives the public benefit is diminished. This is because ineffective competition or anti-competitive behaviour will be passed though to final consumers. Network pricing is a crucial feature of any access regime and for this reason the Commission has undertaken detailed analysis of the network pricing proposals and issues surrounding it as part of its assessment of the NEM access code.

Issues arising in response to the draft determination

In its draft determination, the Commission highlighted a range of concerns associated with the Code's network pricing arrangements. Drawing on the analysis of the Commission's *NEM Access Code Draft Determination*, the Commission recommended that the jurisdictional regulators be statutorily independent of executive government by the time of the commencement of the NEM's network pricing regimes in 1999.

The Commission also expressed concerns on the incidence of network charges whereby the great proportion of network charges would be levied on customers. As a result, network charges would provide little incentive for the efficient location of generation options and would disadvantage embedded generation options. While it sought to have these issues re-examined as part of the NECA pricing review, the Commission did not want to pre-judge the outcome of the review. In the interim, the Commission imposed the following condition of authorisation:

C11.1 Chapter 6 must be amended to provide for distribution NSPs to negotiate with embedded generators on the pass-through of savings in transmission use of system charges, based on the approach adopted by IPART.

At the pre-decision conference and in subsequent submissions the applicant, market participants and the network service providers acknowledged the merits of the Commission's arguments. Despite this broad support, many questioned the Commission's approach and condition of authorisation.

Users' response

Rather than imposing an IPART style 'with and without' test, a number of participants (eg Ampol, the ACA, Australian Paper and the EUG) argued that the Commission's interim position should be to levy TUOS charges on generators. For example, the EUG argued that, notwithstanding the NECA review, the Commission should provide a more concrete direction on network pricing. The EUG and Cadia Mines sought the unbundling of transmission (TUOS) and distribution (DUOS) use of system charges, and the EUG added that at least 50 per cent of TUOS charges should be levied on generators.

To the extent that generators commented on network pricing issues, their concerns were focussed on firm access issues which are discussed elsewhere in this Determination and as part of the Commission's decision on the NEM Access Code.

The BCA supports the Commission's condition for the interim application of an IPART type test, but does not support the proposed prices methodology and allocation of costs to customers.

Networks' response

The incumbent New South Wales distribution NSPs argue that the regulatory arrangements for network pricing for generators should provide efficient locational signals across transmission and distribution networks. The New South Wales distribution NSPs, United Energy and TransGrid agree that this is an issue for the NECA review.

The distribution NSPs question whether the IPART guidelines are workable, adding that they have never been tested or used on any embedded generation scheme in New South Wales. Similarly, Powercor supports the general thrust of the Commission's recommendation but argues that the IPART guidelines do not provide sufficient detail for specific projects and may lead to sub-optimal outcomes if the regulatory environment is not fully considered. SEQEB argues that the IPART guidelines were just one approach and it proposed a number of Code consistent alternatives.

In terms of the powers of the regulators, the New South Wales distribution NSPs and TransGrid are both concerned that the regulator should not attempt to run the network businesses. The New South Wales distribution NSPs acknowledge that the regulator should have reasonable information gathering powers while TransGrid argues that the standard financial reporting requirements would be sufficient. However, the distribution NSPs stress that if the regulator has power to independently disclose information, then the networks should have appeal rights to a court of law in the event of a dispute.

Many Victorian DNSPs raise concerns regarding changes to network pricing arrangements and the report on their pricing arrangements which have been established under the Tariff Order.

CitiPower and Powercor indicate that they see merit in having ring fencing guidelines relating to the accounting separation for regulated and non-regulated activities. Beyond this, Powercor does not support full functional separation arguing that it would increase costs to end customers by requiring the businesses to duplicate corporate overhead, billing and settlement functions. Solaris and United Energy support the Victorian approach where functional separation involves accounting separation and information control rather than corporate disaggregation.

Applicant's response

The applicant noted that jurisdictional regulators in New South Wales (and the ACT) and Victoria are already statutorily independent of their governments. Moreover, that Queensland has proposals for establishing a separate regulatory authority and that South Australia's arrangements (including independence from executive government) will be reviewed over the next twelve months.

The applicant confirmed that the NECA pricing review would examine the basis for connection charges for new generators and signalled its intention to include in the Code an interim measure, such as IPART's 'with and without' test.

Commission considerations

Following the pre-decision conference and subsequent submissions, the Commission maintains its concerns regarding the impact of network pricing arrangements on the level of public benefit likely to flow from the NEM arrangements. The Commission's specific concerns regarding the possible competitive effects of the network pricing provisions relate to the independence and powers of the network pricing regulators, and the incidence of network charges.

Independence and powers of jurisdictional regulators

The Commission believes that in general, the Code's proposed regulatory regime for distribution network pricing acts in the interests of NSPs, network users and the general public. While outcomes from the process cannot be guaranteed, flexibility is necessary to ensure that distribution network prices periodically respond to changing circumstances. In coming to this conclusion, the Commission places significant reliance on the jurisdictional regulator's independence as well as the sanctions for non-compliance with the Code.

However, decisions confirming the independence of jurisdictional regulators have not been finalised in all of the participating jurisdictions. Consequently, to reduce the likelihood, and perception, that the electricity pricing regime will be used to inflate the asset base of publicly owned utilities, the Commission recommends the jurisdictional regulators be statutorily independent of executive government by the time of the commencement of the NEM's network pricing regimes in 1999.

The Commission also considers that the transmission network pricing regulator must have sufficient powers to perform its functions under the Code; in particular, in relation to information requirements, public disclosure of relevant material and ring fencing guidelines dealing with accounting separation and information flows.

At the time of making this determination, a number of aspects of the powers of the transmission regulator have yet to be finalised. The Commission is concerned about the lack of certainty this creates for the NEM arrangements. In terms of assessing the overall public benefit of the Code, the Commission's expectation is that an operative access regime will be in place. This expectation is on the basis of the obligations Part IIIA of the TPA imposes onto the transmission and distribution NSPs as well as that an access code application has also been submitted to the Commission for acceptance. However, if this expectation proves false and an effective access regime is not in place, the Commission believes that the expected balance between public benefit and anti-competitive detriment may be materially different and may provide grounds for the Commission to revoke this authorisation.

Locational signals

The Commission is concerned that the current Code proposal, whereby the great proportion of network charges will be levied on customers, provides little incentive for the efficient location of investment in network or generation options. Locating generation facilities close to load can lead to significant network savings, but if the network charges do not enable the owners of generation assets the benefits of locating close to load (i.e. savings on network charges), the incentives for investment decisions are lost or muted. As generators compete on a delivered cost basis, this incidence of network charges disadvantages embedded generation options. Nevertheless, the Code recognises this deficiency and encompasses limited options to overcome this and other deficiencies in the network pricing regime (i.e. payments from distributors to embedded generators).

Clearly, the Commission is concerned that these deficiencies in the Code may be contrary to the interests of embedded generators, thereby impacting on the anti-competitive detriment of the NEM arrangements. However, the Commission is not currently in the position to accept the users' arguments to impose conditions to alter the incidence of TUOS charges. Network pricing is a complex issue involving many trade-offs and changes to the incidence of network pricing may have unforseen consequences. Therefore, the Commission accepts the applicants' arguments that this issue should be assessed as part of the NECA pricing review. In any event, the applicant has indicated its intention, as an interim measure, to insert into the Code a mechanism similar to IPART's 'with and without' test.

The Commission's acceptance of the applicants' position has been on the basis that the Code will deliver overall public benefits provided the concerns of users will be addressed in, and the necessary code changes will be made as a result of, NECA's review of network pricing. However, if the NECA review is unable to deliver Code changes which result in a more efficient set of network prices, then the expected balance between public benefit and anti-competitive detriment may be materially different and may provide grounds for the Commission to revoke this authorisation.

Overall assessment

Efficient network pricing arrangements are crucial to realising the public benefits from introducing the NEM. In terms of assessing the overall public benefit of the Code, the Commission's expectation is that an operative access regime will be in place which includes effective regulators and efficient network prices. This expectation is on the basis of the obligations Part IIIA of the TPA imposes onto the transmission and distribution NSPs as well as that an access code application has also been submitted to the Commission for acceptance. However, if this expectation proves false and an effective access regime is not in place, the Commission believes that the expected balance between public benefit and anti-competitive detriment may be materially different and may provide grounds for the Commission to revoke this authorisation. The Commission's detailed analysis of the access arrangements and a fuller discussion of issues surrounding network pricing is contained in the *NEM Access Code Draft Determination*.

12. Metering

Metering measures and records the flow of electrical energy. By measuring the electricity flowing through participants' metering points, the amount of electricity produced and consumed can be determined and settlements effected. For this reason metering is fundamental to the efficient functioning of both the wholesale and retail markets. It is also essential for a network-based system in which the suppliers of the energy consumed by any particular purchaser cannot be identified.

Chapter 7 of the Code sets out the rights and obligations of Code participants with respect to metering. The relevant Code participants are local NSPs,[85] market customers (in respect of any metering point through which they purchase any market load or sell any second-tier load), market generators and Metering Providers. The chapter only covers the wholesale market but non-market generators and market customers may voluntarily comply with its provisions. Retail metering is being developed independently of the Code. Clause 7.1.3 sets out the key principles adopted in Chapter 7.

Where a market participant fails to comply with its metering obligations, NEMMCO may refuse to permit it to participate in the market in respect of any connection point. A refusal by NEMMCO is a reviewable decision.

12.1 Metering installations

Any market customer wishing to trade in the wholesale market will be required to install a meter for each connection point. A contestable customer who takes supply from a retailer other than the local retailer (second-tier customer) will also require a half hourly meter with an associated communication system, even if the customer does not buy from the wholesale market, and must comply with the Code's detailed provisions relating to such metering installations.

Clause 7.2 states that a 'responsible person' is the person who has responsibility for the provision of a metering installation, being either a local NSP or the market participant. Schedule 7.3 sets out the responsibilities of the responsible person with respect to testing metering installations. If requested, a local NSP must provide, install and maintain a market participant's metering installation. Alternatively, the market participant is responsible and must engage a Metering Provider for this purpose.

Clause 7.3.1(a) sets out the technical requirements of a metering installation — it may consist of certain combinations of components and facilities. The class of metering installation and accuracy requirements for a metering installation at each metering point must be determined using Schedule 7.2 based on the annual amount of active energy which passes through that metering point. Metering installations in use at market commencement must conform with the provisions of Chapter 9 of the Code.[86]

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[85] Chapter 10 of the Code defines a local NSP as the NSP within a local area to which that geographical area has been allocated by the jurisdictional regulator.

[86] Metering derogations are discussed in section 14.8.7.

The market participant is responsible for payment of all costs associated with the provision, installation, maintenance, routine testing and inspection of the metering installation (clause 7.3.6). Any costs incurred in gaining access to metering data must be paid for by the party who obtained the metering data. The cost of requisition testing and audits must be paid for by the party requesting the test or audit, except where the metering installation is shown not to comply with the Code, in which case the responsible person in relation to that metering installation must bear the cost.

Under clause 7.6 metering installations are to be tested in accordance with the inspection and testing requirements in Schedule 7.3. NEMMCO may make appropriate corrections to the metering data to take account of any errors and to minimise adjustments to the final settlements account (clause 7.6.2(b)). Clause 7.6.3 provides for audits of metering data and stipulates that NEMMCO must carry out periodic random audits of metering installations to confirm Code compliance.

There are also provisions dealing with the security of metering installations and data (clause 7.8) and the performance of metering installations (clause 7.11).

Issues for the Commission

The requirements of the Code mandating:

- the installation of metering of a particular standard and the standards for revenue and check metering installations;

- that the components and requirements of a metering system and metering communication links be of a certain type of performance characteristics; and

- that metering generally only be used for metering of wholesale electricity supplies,

may contravene the TPA in being potentially exclusionary provisions, exclusive dealing, or having the effect or likely effect of substantially lessening competition in the NEM or the market for meters.

The Commission is also concerned with the requirement that second-tier customers have to install metering to standards set out in the Code, which may reduce competition at the retail level and reduce the overall level of public benefit arising from the NEM arrangements.

The Commission also considers the public benefits of the NEM arrangements will be enhanced if the auditing arrangements of metering installations are such that market participants have a high degree of confidence in the metering data.

What the interested parties say

The EUG, Tasmanian Government, NFF, Integral Energy, the ERTF and Australian Paper are concerned with the costs of having to install metering of a required standard and the impact this will have on competition.

What the applicants say

The applicants state that second-tier customer loads are registered so that the market consumption of a market customer (local retailer) may be adjusted when a second-tier customer purchases electricity from another market customer (non-local retailer). The applicants point out that when a customer (e.g. second-tier customer) within the distribution network no longer buys electricity from the local retailer, there is a requirement to subtract the second-tier customer's load from the total market loads of the local retailer to avoid double counting. Before this adjustment is made, the non-local retailer of the second-tier customer is required to register that customer's connection point as one of its market loads. In effect, every retailer's total consumption becomes the sum of its registered market loads across the interconnected system.

The applicants argue that each of the Code's metering installation requirements provides public benefit which outweighs any associated anti-competitive detriment.

The applicants contend that compliance with metering installation standards is necessary in an electricity supply market to determine usage and to serve as a basis for financial settlement and management of both usage and delivery. The central role metering plays means that there must be recognised standards upon which all participants can rely. The applicants suggest that the Code documents such requirements in a transparent and unambiguous manner. Without these requirements the applicants argue that confidence in the market would be undermined and the performance of the financial settlement system subject to doubt. Further, the applicants submit that any possible public detriment arising from the requirement to comply with the Code's metering standards is minimal.

They state that all the specifications are necessary for the proper functioning of a low cost, automated, modern metering system and contend that the metering installation provisions are intended to be technologically neutral, which is also in the public interest.

The applicants also suggest that the requirement for each metering installation to have an associated telecommunications link increases the public benefit accruing from a market served by a modern reliable and low cost metering system, which is accessible via telecommunications for remote polling of metering data.

The applicants submit that accuracy levels and time limits are necessary to poll meters and take readings every 30 minutes, and that the other standards in clause 7.11 reflect the collective experience of the industry on availability and repair times.

Issues arising from the draft determination

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

C12.1 Chapter 7 must be amended before 1 July 1998, to include new metering requirements for smaller contestable customers, less than 750MWh per annum, such that the costs of compliance will not effectively prevent smaller contestable customers purchasing from retailers other than the local retailer.

C12.2 Clause 7.2 must be amended to explicitly permit market participants to change Metering Providers after the meter has been installed.

C12.3 Clause 7.6.1(d) must be amended to allow NEMMCO unrestrained access to a metering installation for the purpose of testing the metering installation.

C12.4 Clause 7.6.3(d) must be amended to allow NEMMCO unrestrained access to conduct periodic random audits of metering installations.

C12.5 Clause 7.6.1(e) must be amended so that the person who tests a metering installation must make the test results available to all interested parties.

C12.6 NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of the Code regarding the role of responsible persons. The review must consider possible conflicts of interest of persons performing that role, particularly where the responsible person is a market participant which takes energy from a NSP. The review must also consider any steps which might be taken to remove or ameliorate the effects of any possible conflict of interest it identifies.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

The majority of comments received from interested parties focus on the condition relating to metering requirements for smaller customers and the condition permitting market participants to change metering providers.

The EUG supports condition C12.1 and suggests that there should be effective co-ordination between jurisdictions on this issue.

TransGrid supports condition C12.1, however they argue that the necessary amendments must be made earlier than 1 July 1998, to give metering providers adequate time to order new equipment. It also draws the Commission's attention to work undertaken by the Office of the Regulator General, Victoria (ORG), NEMMCO, TransGrid and the New South Wales Department of Energy to devise a satisfactory solution to the problem of smaller tranche customers.

CitiPower argues that the Code must state that host distribution businesses should not bear any additional costs as a result of new metering requirements for smaller customers.

Solaris argues that the Commission's condition to include new metering requirements for smaller contestable customers 'seems to raise as many questions as it answers'. Solaris argues that the real issue is whether the cost of alternative methods of market settlement is less expensive. Solaris also believes that NECA should conduct a review of both metering technology and market settlement options to allow more cost reflective options to be identified before any changes are made to the Code.

United Energy argues that deemed load profiling should not be considered as a solution if the cost of metering for smaller customers is excessive. It argues that deemed load profiling has the potential to deliver an extremely inefficient outcome by not allowing true pricing signals at times of system stress.

Eastern Energy argues that the requirements for customers below the 160MWh/ year tranche will be dependent on technology and may require further amendments post-July 1998.

Australian Paper argues that the draft determination does not adequately address the major concern of smaller customers. It states that the ACCC should specifically mandate ways that are acceptable as alternatives to overcoming this metering cost.

TransGrid supports condition C12.2 provided it makes explicit provision for the commercial rights of the original metering provider, and the necessity for NEMMCO to be provided with uninterrupted data pertaining to metered consumption before and after the change.

CitiPower claims that the solution preferred by the Commission is likely to be highly inefficient and seems to ignore the role of the NSP who should not bear any additional costs or risk as a result. It argues that the proposed condition has the potential to cause confusion and delays arising from uncertainty of who will provide metering services. At the pre-decision conference, energyAustralia argued that while they would like to see contestability in the provision of metering services, the Code needs to be amended to ensure a continuity of data is achieved when metering facilities are changed.

Eastern Energy argues that adoption of this principle would require that adequate provision be made for the recovery of costs associated with the metering. A change in metering provider would require the former metering provider be compensated for any losses incurred. It adds that it is inefficient for a recently installed meter to be removed and replaced just because of a change in meter provider. It argues that there needs to be some process to ensure efficiency in this procedure.

In a joint submission, the New South Wales DNSPs argue that the Code should provide for the metering provider to consult with the local NSP before altering a metering installation. This is necessary as the NSP requires this information to review the structure of network tariffs for the customer and advise them accordingly.

In relation to condition C12.6, CitiPower argues that the introduction of competitive metering should be delayed until this review has been completed and the benefits demonstrated to outweigh the costs.

Commission considerations

The Commission acknowledges that detailed metering installation provisions are required in the Code. Any electricity supply market requires reliable metering to determine usage and to serve as a basis for financial settlement. The central role of metering in the operation of the market means that it must meet recognised standards upon which all participants can rely.

The Commission has concerns, however, as to whether the competitive benefits at the retail level will be realised given the number of fixed and annual costs associated with metering installations. The costs include the cost of the meter, the cost of the communications link, and the cost of data analysis for calculating settlement. In addition, the appointment of a responsible person may be impracticable for installations below 1GWh per annum, and accordingly may heighten entry barriers for smaller market participants. In fact Western Power suggests that the responsibilities of the responsible person defined in clauses 7.2.5, 7.5.2(b), 7.8.1(a) and 7.8.2 are too onerous for low voltage market customers.

These concerns are highlighted by the fact that from 1 July 1998, second-tier customers in the 160–750MWh/ year tranche will have the obligations of Chapter 7 imposed upon them. As the cost of half hourly metering for these smaller customers is likely to outweigh any gains from changing retailers, second-tier customers may be forced to remain with their host retailers.

The Commission is aware of the metering proposal for the 160–750MWh/ year tranche of customers developed by the ORG, in consultation with NEMMCO, the ERTF, TransGrid, VPX and the Energy Projects Division of the Victorian Department of Treasury and Finance. This proposal involves recovering the cost of acquiring second-tier customers' metering data for settlement from both local and second-tier retailers. The ORG argues that the current method of recovering the cost from second-tier retailers only will be a barrier to competition for customers in the 160–750MWh tranche because the costs of changing retailer will be significant. The ORG claims that the costs of acquisition of second-tier meter data for settlement should be shared because such data benefits both local and second-tier retailers and facilitates the operation of the wholesale market.

The Commission considers that the metering provisions must allow for alternative metering solutions for consumers beneath an annual usage level of 750MWh, which are commercially and contractually acceptable. The Commission also considers that such changes should be made before the next tranche of customers becomes contestable in July 1998. The Commission rejects the suggestion made by Solaris that it is the Commission's role to mandate alternatives to the current metering requirements for small customers. It is more appropriate that the technical detail involved in assessing alternatives such as load profiling be considered by the industry rather than the Commission.

The Commission considers that an investigation should be made of practical alternatives to having smaller customers comply with the wholesale metering requirements. This may just be a question of risk allocation between the host and independent retailers and the customer involved and perhaps some later adjustment based on periodic meter readings. There may also be a role for metering agents here or for harmonisation of retail metering requirements between the jurisdictions. New metering technology will also be very important.

As part of an investigation of practical alternatives for small customers, the Commission recommends that NECA consider the feasibility of the proposal put forward by the ORG for customers in the 160–750MWh tranche.

The Commission has a number of specific concerns with certain metering installation provisions. The Code does not appear to explicitly allow for a market participant to change the Metering Provider for ongoing metering support after the installation and commissioning phase. Such 'locking in' of customers would preclude competition between Metering Providers in the area of metering support. Accordingly, the Commission requires that clause 7.2 be altered so as to expressly permit market participants to change Metering Providers after the meter has been installed.

The Commission notes comments arising from the draft determination that this condition may be inefficient and has the potential to cause confusion and delays arising from uncertainty of who will provide metering services. The Commission also acknowledges that allowing customers to change Metering Providers raises issues of ownership of meters, data compatibility and access to data. The applicants have informed the Commission that the metering chapter of the Code will be reviewed before market commencement. The Commission considers, therefore, that such issues should be addressed in that review, to ensure that competition among Metering Providers is achievable.

The Commission has further concerns with the provision that NEMMCO must negotiate with the responsible person when undertaking testing. Western Power has suggested that one of the significant factors in preventing electricity theft is the unrestricted right of access without notice. The Commission considers that the Code must be altered to provide NEMMCO with unrestrained access to the metering installation when testing and conducting random audits of metering installations.

The Commission is also of the view that the responsible person would appear to be given a degree of self regulation in the Code which is in conflict with his/her interest in the metered data. There is ambiguity as to whether the Code obliges a responsible person to report all testing to NEMMCO (see Schedule 7.3, clauses 1(a) and 1(f)(1)). This is particularly the case if the responsible person is also a market participant and takes energy from an NSP. Conceivably the responsible person may choose to only disclose metering errors that are in his/her favour. This will be against the interests of an NSP at the distribution level who is depending on the spread of metering errors at exit points across its network to balance and will presumably be liable for this contrived underpayment as losses attributed to its network. This is a major shortcoming of the metering installation requirements which needs to be addressed.

The applicants have responded to the Commission's concerns. The applicants state that by including in clause 7.13 the requirement for annual reviews of Chapter 7, the Code acknowledges the need for considerable further work on metering. This has been reinforced by the experience so far in the New South Wales and Victorian State markets. The applicants state that the aim will be, if at all possible, to have completed the first of those annual reviews, and introduced amendments to Chapter 7 in the light of that review, in time for the full national market.

The applicants agree that NEMMCO will require random access to meters in appropriate circumstances and agree that a Code change to put this beyond doubt may be appropriate.

Conditions of authorisation

C12.1 Chapter 7 must be amended before 1 July 1998, to include new metering requirements for smaller contestable customers, less than 750MWh per annum.

C12.2 Clause 7.2 must be amended to explicitly permit market participants to change Metering Providers after the meter has been installed.

C12.3 Clause 7.6.1(d) must be amended to allow NEMMCO unrestrained access to a metering installation for the purpose of testing the metering installation.

C12.4 Clause 7.6.3(d) must be amended to allow NEMMCO unrestrained access to conduct periodic random audits of metering installations.

C12.5 Clause 7.6.1(e) must be amended so that the person who tests a metering installation must make the test results available to all interested parties.

C12.6 The Code must be amended to provide that NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of the Code regarding the role of responsible persons. The review must consider possible conflicts of interest of persons performing that role, particularly where the responsible person is a market participant which takes energy from a NSP. The review must also consider any steps which might be taken to remove or ameliorate the effects of any possible conflict of interest it identifies.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

12.2 Metering Providers

Clause 7.4 relates to Metering Providers. A Metering Provider is a person who meets the requirements listed in Schedule 7.4 and is registered with NECA as such. Installation and maintenance of metering installations must only be carried out by a Metering Provider, who is also responsible for providing and maintaining the security controls of a metering installation in accordance with clause 7.8.2.

Any person may apply for registration as a Metering Provider and NSPs must either register as Metering Providers or enter into agreements with Metering Providers for the provision of metering services.[87] Restrictions are placed on market generators, market customers and traders who are involved in the trading of energy. These categories of participants cannot be registered as Metering Providers for connection points in respect of which the metering data relates to their own use of energy but they may act as the responsible person. However, if a market participant is a market customer and also an NSP, then the market participant may register as a Metering Provider for that connection point.

Schedule 7.4 provides that a Metering Provider must be registered with NECA, for the type of work the Metering Provider is qualified to provide. NECA must establish a qualification process that enables registration to be achieved in accordance with Schedule 7.4. The qualification process must include an agreement between NECA and the Metering Provider which ensures that the Metering Provider accepts all relevant responsibilities under the Code. The Metering Provider must also meet applicable State and Territory licensing requirements.

Metering providers will be categorised under the Code according to their competencies based on categories of metering installation. There are ten registration categories for Metering Providers as well as an approved communication link installer category. Schedule 7.4 sets out the capabilities category 1A, 2A and 3A Metering Providers must be able to exhibit to the reasonable satisfaction of NECA. The other seven categories of Metering Providers and approved communication link installers do not have specific capabilities set out.

Issues for the Commission

Clause 7.4 and Schedule 7.4 contain provisions compelling Code participants to use only licensed Metering Providers, and limits the extent to which market participants may perform such metering work..

It is possible to construe such provisions as being provisions, exclusive dealing including third line forcing, or having the effect or likely effect of substantially lessening competition.

What the interested parties say

A number of interested parties have raised issues relating to the qualifications required for Metering Providers, the risks associated with them, whether metering provision and data collection should be contestable and whether or not there is a need for separate Metering Providers.

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[87] The role of NSPs and the responsible person are discussed in section 12.1.

In terms of the qualifications of Metering Providers, the EUG argues that the categories of registration and the competency gradations will restrict customers in their choice of Metering Provider and could increase the costs involved. It suggests that it may be preferable to provide for voluntary registration or accreditation with NECA and rely on the metering standards for compliance.

In contrast, Integral Energy submits that the requirements for Metering Providers in Schedule 7.4 lack clarity. It states that in Schedule 7.4 clause 3(b)(6) reference is made to 'compliance' with ISO/IEC Guide 25 'General Requirements for the Competence of Calibration and Testing Laboratories.' It suggests that in order to eliminate any subjectivity in this matter further clarification of 'compliance' is required.

The ERTF argues that the metering and data collection functions can be readily decentralised and contested. It suggests that competition in the provision of data collection services should bring down costs and allow individuals to tailor data collection to meet the needs of their customers as well as those of NEMMCO. It says this will also help meet the significant expansion that can be expected in this activity, promote innovation and give greater incentives and opportunities for individual retailers to achieve high standards in the quality of data provision for their customers.

The ERTF also submits that the retailer of choice is best placed to take accountability for meter provision and data collection (the role of meter agents). It says that appropriate procedures need to be in place to ensure meter data accuracy, auditability and customer protection. In terms of risk management, it is suggested that some risk of malfunction will continue to exist and the retailer of choice should be accountable to NEMMCO for correct operation of metering and data collection.

The TransGrid submission says that in New South Wales attempts have been made to establish contestability and that it would be keen to see Chapter 7 of the Code require contestability in both metering provisions and metering agents.

The Victorian DBs have queried whether there is a need for separate Metering Providers. It states that there are issues that must be considered before such arrangements can be implemented, including ownership of the meter and the merits of interposing another party (Metering Provider) into an already complicated arena where customers, retailers and the NSPs will interface. It is contended that the objective is to reduce metering costs and to minimise the extent to which these costs can be a barrier to customers switching between competing retailers.

What the applicants say

While recognising the possible anti-competitive effects of the Metering Provider arrangements, the applicants argue that the integrity of the metering system depends in part on the reasonable quality of the persons who operate in the capacity of Metering Providers. The applicants suggest that the real issue is not whether it is acceptable to require Metering Providers to be registered and to be qualified, but whether the process and standards involved are excessive in comparison with the benefits of not having qualified and registered Metering Providers. The applicants contend that they are not.

They argue that the public benefit in the market and the reliance on the integrity of the metering system requires that competent Metering Providers perform metering work appropriate to their qualifications. The applicants state that the categories of registration and the competency gradations associated with each reflect divisions that are meaningful and traditional within the industry. The Code is therefore, it is contended, attempting to reflect the industry's understanding of best practice, rather than to create new divisions and distinctions.

The applicants feel that, rather than specify courses or qualifications which may be available from educational institutions, the Code sets out the competency standards that the industry considers appropriate. This leaves it open for individuals to present to NECA evidence of new ways in which competency might be demonstrated and increases the possibility for entry of new providers into the industry.

Issues arising from the draft determination

EnergyAustralia submits that current and proposed rules for tying metering provision and metering data provision to either retailers or distributors should specifically not be authorised.

Commission considerations

The Commission considers that there is a significant public benefit associated with the provision of reliable metering and believes that this should be done in a competitive manner. This is because reliable metering will enhance the overall integrity of the NEM while ensuring that any benefits accruing as a result of the introduction of competition are realised. For example, in the case of large users, even small errors in metering can amount to considerable financial losses.

The Commission notes the applicants' argument that the real issue is not whether it is acceptable to require Metering Providers to be registered and to be qualified, but whether the process and standards involved are excessive. The Commission has also noted Western Power's view that in general Chapter 7, in its current form, does not obstruct entry but rather Chapter 7 does not define clearly enough the responsibilities of Metering Providers. Western Power suggests that this lack of definition may lead to unnecessary metering disputes and the need to remedy substandard metering installations following the possible default of the Metering Provider. These arguments are considered below.

If the entry of Metering Providers is restricted in some way this could give rise to market power among Metering Providers which they would not otherwise possess. This needs to be weighed against the necessity that Metering Providers are qualified to deliver an accurate service. The Commission notes that the Code fails to set out any guidelines for qualification. Further, it is not clear from the Code whether a provider can apply for more than one type of competency or whether registration can be altered given new competencies and/or technology. Nor is it clear how competencies for lower levels of providers will be assessed. The Commission recommends therefore that the qualification processes include requirements for all Metering Providers and that they are consistent with the Code's pro-competitive intentions.

Western Power has suggested a Metering Provider should be accredited by the National Association of Testing Authorities, or any other suitable accreditation agency, to hold the type of licence for which it has applied. The Commission agrees that accreditation by an independent agency with technical expertise in testing for compliance with standards is preferable. This would ensure that anyone suitably qualified would be able to obtain a Metering Provider's licence. The cost of independent assessment could be included in any licence application fee.

The Commission notes Integral Energy's submission that the requirements for Metering Providers in Schedule 7.4 lack clarity. It notes that in Schedule 7.4 clause 3(b)(6) has been amended such that the 'compliance' is with regard to the calculation of uncertainties and accuracy. Integral Energy suggests that in order to eliminate any subjectivity in this matter further clarification of 'compliance' is required. The Commission considers that standards set minimum requirements which must be met. Assessment by an independent body should determine whether or not a Metering Provider is capable of meeting that standard.

Metering Providers must also be licensed in accordance with State and Territory licensing provisions. The Commission is concerned that the costs and criteria for such licences may vary widely from jurisdiction to jurisdiction and may constitute a barrier to entry for potential Metering Providers wishing to be licensed in several jurisdictions. Further, there is concern that the cost to Metering Providers of having to meet at least two sets of licensing criteria, if operating in more than one jurisdiction, as well as the burden of multiple licensing fees may constitute a barrier to entry to the industry. The Commission therefore recommends that participating jurisdictions consider implementing a regime of mutual recognition in order to increase the scope for competition in the electricity industry and avoid the dissipation of the NEM's public benefits through regulatory requirements.

The ERTF raises the issue of whether the functions of Metering Agents (the ERTF defines these as persons responsible for data collection) can be opened to competition and contestability. The Commission considers, based on the information available, that such a scheme would be worthwhile as it would reduce costs and increase dynamic efficiency through innovation in both metering provision and data collection. The Commission recommends that the contestability of Metering Agents should be considered by NECA or NEMMCO in any process to amend Chapter 7 of the Code.

The applicants have responded to the Commission's concerns and have agreed that the Metering Agent function will be contestable. They state that NEMMCO will establish a process to achieve this by accrediting Metering Agents. The financially responsible market participant will then be free to select an accredited agent based on price and level of service. Amendments will be introduced to streamline this process by establishing Metering Agents on a contestable basis under the Code.

In response to the Commission's draft determination, energyAustralia have commented that current and proposed rules for tying metering provision and metering data provision to either retailer or distributor should specifically not be authorised. The Commission considers that the Code does not specifically tie metering provision and metering data provision to the retailer or the distributor, because it allows any person to register as a Metering Provider. It would surely be in the market participant's commercial interest to purchase metering services from the lowest cost Metering Provider rather than necessarily providing the service themselves.

There is however the potential for a number of conflicts of interest to arise as a result of the provisions in Chapter 7. For example, restrictions are placed on market generators, market customers and traders who are involved in the trading of energy. Certain participants cannot be registered as Metering Providers for connection points in respect of which the metering data relates to their own use of energy, however, if a market participant is a market customer and also an NSP, then the market participant may register as a Metering Provider for its connection point. The Commission is concerned that allowing a market customer who is also an NSP to provide its own metering may give rise to perverse incentives which may compromise metering accuracy thereby reducing the public benefits associated with accurate metering. The Commission notes that NEMMCO may conduct random audits metering installations and recommends that such metering points be subject to random audits to ensure accuracy is maintained.

The Commission also draws attention to the fact it has imposed a condition of authorisation requiring a review of the role of the responsible person within one year of NEM commencement. This review will consider any possible conflicts of interest that may arise where the responsible person is a market participant (such as a retailer) and takes energy from a NSP.

Insofar as the licensing of Metering Providers constitutes exclusionary or exclusive dealing conduct, the Commission recognises that licensing is an essential feature of ensuring that reliable metering is provided. It may be that this requirement excludes people who want to engage in the market but do not want to be licensed and this could lessen competition. However, failure to provide reliable metering is potentially costly to market participants and hence there is net public benefit in requiring Metering Providers to be licensed.

Overall, the Commission acknowledges the fundamental need for accurate metering and recognises that Metering Providers are integral to this requirement. Therefore, the Commission is of the view that Metering Providers should be registered as this would assist in avoiding any unnecessary metering disputes and the need to remedy any sub-standard metering installations following the possible default of a Metering Provider. The Commission believes that the recommendations contained in this section would assist in overcoming the problems discussed above while at the same time addressing concerns raised by interested parties.

12.3 Rights of access to data

Clause 7.7 limits direct or remote access to metering data from a metering installation, the metering database or the metering register in relation to a metering point to persons associated with the meter, metering point or connection point, and to NEMMCO and NECA (or their agents). NEMMCO must ensure that access to metering data by these persons is scheduled appropriately to ensure that congestion does not occur.

Electronic access to metering data from a metering installation shall only be provided where passwords are allocated, otherwise access to metering data is to be from the metering database. Clause 7.10 provides that metering data and passwords are confidential data and are to be treated as confidential information in accordance with the Code.

Issues for the Commission

The Commission considers that the public benefits of the NEM arrangements will be enhanced if metering data is only available to those persons with a legitimate interest in the data.

Issues arising from the draft determination

In the draft determination, the Commission imposed the following condition of authorisation:

C12.7 Clause 7.7(a)(5) must be amended such that only Market Customers at associated connection points with an interest in the data as specified by the Code are able to obtain the data.

CitiPower argues that the ambiguity of the condition concerning whether retail and network participants are included in the term ‘market customers’ must be removed. It argues that they have a vital interest in the data.

Commission considerations

The Commission considers that generally these provisions enhance the public benefit by maintaining the confidentiality of metering data. However, the Commission is concerned that the provision allowing a customer at an associated connection point access to metering data may allow persons who would not otherwise have access to the data to obtain it. This situation may arise because the provision is ambiguous. The Commission recommends, that this provision be clarified such that only market customers at associated connection points with an interest in the data, as specified by the Code, be able to obtain it.

The Commission notes that CitiPower’s concern that network participants need access to the metering data is addressed by clause 7.7(a)(3) which allows the NSPs associated with metering point to have either direct or remote access to metering data.

Further, under clause 7.7(c) NEMMCO must ensure that access to metering data from the metering installation is scheduled appropriately to ensure that congestion does not occur, whereas clause 7.1.3 states that the electronic accessibility of each metering installation must be co-ordinated by the responsible person to prevent congestion. These two provisions appear to be inconsistent and the Commission recommends that they be clarified.

12.4 Processing of metering data for settlements purposes

Clause 7.9 makes provision for the establishment of a metering database, NEMMCO’s responsibility for remote acquisition of data, periodic energy metering, and validation and substitution of data and errors found in metering tests.

Issues for the Commission

Given that persons who wish to trade in the wholesale market must comply with the provisions of the Code, including the metering provisions, the issue for the Commission is whether the provisions for the processing of metering data for settlements purposes are as fair and accurate as possible and enhance the public benefit without imposing undue costs on participants.

What the interested parties say

The Victorian DBs suggest that accuracy could be compromised by allowing NEMMCO to use agencies to collect metering information and by enabling agency databases to form part of the metering database (clauses 7.9.1(b) and (c)). They suggest that agencies are not bound by the Code unless they are local NSPs, market customers, market generators, or Metering Providers. This could result in a situation where critical metering information is under the control of persons not bound directly by the Code. They contend that this poses the unacceptable risk that accuracy could be compromised if data held in the agency databases is not subject to rigorous requirements for accuracy through compliance with the Code. The

Victorian DBs contend that the performance standards and obligations of the agency databases to be used by NEMMCO should be prescribed by the Code. Agencies should be bound by the Code in relation to all relevant matters, including dispute resolution when there are disagreements about the metered data.

In relation to periodic energy metering, the Victorian DBs state that all meters installed in Victoria for the purposes of pool participation have 15 minute recording intervals which are a sub multiple of the trading interval. They suggest that current drafting of clause 7.9.3 represents an unacceptable risk that existing metering arrangements may need modification if agreement was not reached with NEMMCO or the market participant. They also note that the derogation under clause 9.9.9 of the Code may not be required if the Code directly accommodated the 15 minute interval.

With respect to data validation and substitution, energyAustralia submits that where metering data cannot be used for the purposes of settlement, the data substitution must be undertaken in consultation with all affected Code participants, not just with the ‘market participant and the local NSP’ as envisaged by clause 7.9.4(d). Further, it contends that where substitution is used, all Code participants whose settlement statement is impacted on by the energy going through that metering installation should be informed that data substitution has been necessary.

The Victorian DBs submit that accurate metering data forms a critical link in the commercial transactions of Code participants. It is inevitable that circumstances will arise where accurate metering data is not available due to meter failure, or other causes, and NEMMCO must develop data substitution processes in consultation with Code participants for application under clause 7.9.4(d) in such circumstances.

Issues arising from the draft determination

In the draft determination, the Commission imposed the following condition of authorisation:

C12.8 Chapter 7 must be amended to include guidelines relating to substitution and validation of data, to be developed by NEMMCO using the Code consultation procedures, prior to the commencement of the NEM.

TransGrid questioned whether this condition is necessary, as the New South Wales State market has operated effectively without such a requirement in the New South Wales Code.

Commission considerations

Under the Code NEMMCO may use agency databases, but these are not defined anywhere in the Code. The Commission notes the submission of the Victorian DBs and recommends that metering agents be bound by the Code. That is the Commission recommends that the concept of agents be defined in the Code and their role set out in Chapter 7.

In the event that remote acquisition of data becomes unavailable, NEMMCO must arrange with the responsible person to obtain the relevant metering data. The Commission is concerned that this may give rise to a conflict of interest on the part of the responsible person. This is because the responsible person may not have the correct incentives to accurately report the data. Western Power has suggested that this problem would be overcome if the local NSP collected the data. The Commission recommends that either an agent of

NEMMCO or the local NSP obtain the data, or that the data be subject to additional auditing if NEMMCO considers this to be necessary.

The Commission notes the submission from the Victorian DBs which states that existing arrangements may require modification if no agreement as to 15 minute metering can be reached by the market participant and NEMMCO. The Commission considers that the dispute resolution provisions may be used in such circumstances and therefore any market participant aggrieved by its negotiations with NEMMCO could seek to have the matter determined on its merits by a DRP. Further, Victorian meters are covered by the derogation in clause 9.9.9.

The Commission considers that the public benefit of the NEM arrangements will be increased if the metering, validation and substitution procedures are as fair and accurate as possible. The Code does not specifically provide the manner in which data validation and substitution will be carried out but does provide that NEMMCO develop procedures for validation. The Code is silent as to substitution. The Commission considers that a lack of guidelines relating to substitution and validation may lead to disputes over substantial sums of money. The Commission agrees with the submissions of both energyAustralia and the Victorian DBs and is of the view, therefore, that guidelines must be developed by NEMMCO using the Code consultation procedures and that these guidelines must be in place at the commencement of the NEM.

Also, the Code provides that where a check meter is not available, or metering data cannot be recovered from the metering installation within the time required for settlements, then a substitute value is to be prepared by NEMMCO using a method agreed with the market participant and the local NSP. It is unclear whether a substitute value is to be prepared on a case-by-case basis, whether guidelines are to be developed, or whether this is to be part of the connection agreement. The Commission recommends that this ambiguity be clarified prior to commencement of the NEM.

Where a test or audit demonstrates an error of measurement of less than 1.5 times the error permitted by Schedule 7.2, no substitution of readings is required unless, in NEMMCO's reasonable opinion, a party would be significantly affected if no substitution were made. The Commission is concerned that 'significantly affected' is an uncertain term and recommends that this should be clarified. For example, 'significant' may refer to a proportion of annual energy expenditure.

Condition of authorisation

C12.7 Chapter 7 must be amended to include guidelines relating to substitution and validation of data, to be developed by NEMMCO using the Code consultation procedures, prior to the commencement of the NEM.

12.5 Evolving technologies and processes

Clause 7.13 provides that evolving technologies or processes that meet or improve the performance and functional requirements of Chapter 7, or facilitate the development of the market may be used if agreed between the market participant, the local NSP and NEMMCO. In this case, the agreement of the local NSP and NEMMCO must not be unreasonably withheld. In addition NEMMCO is to publish, not later than 30 June 1997 and at least annually thereafter, a report on the application of evolving technologies and processes and a written report to NECA on the extent to which Chapter 7 may need to be amended in order to accommodate the evolving technologies and processes or the development of the market.

Issues for the Commission

The issue for the Commission is whether clause 7.13 may be anti-competitive or may lessen public benefits by not facilitating retail competition through market metering arrangements. This may occur if it suppresses the use of innovative metering which decreases the cost of metering, or it may also reduce the incentive for innovation, particularly in the areas of smart metering (meters which can perform a variety of functions, including load switching, when spot prices increase) and smart switching (switches that will allow customers to change retailers easily).

What the interested parties say

EnergyAustralia submits that it is concerned about what a market participant may propose as falling under 'evolving technologies or processes' as envisaged in clause 7.13. It requests that such technologies and processes should only be implemented after following the Code consultation procedures. It notes that to simply consult only with the market participant and the local NSP is perplexing, since the proposal may impact on the integrity of the market and a number of other market participants. A restricted consultation process in some circumstances may well prove to be appropriate but energyAustralia does not generally support this type of approach. EnergyAustralia suggests that innovation in these areas should not be discouraged but should, however, undergo a reasonable due diligence by the market. EnergyAustralia therefore submits that broader market consultation is required.

Issues arising from the draft determination

In the draft determination, the Commission imposed the following condition of authorisation:

C12.9 Clause 7.13(a) must be amended to state that the agreement of NEMMCO is not unreasonably withheld where the agreement materially affects the interests of persons other than the Market Participant and the local NSP.

Eastern Energy argues that this condition is unnecessary because the existing clause meets the requirement that NEMMCO not unreasonably withhold agreement to the use of evolving technologies or processes.

Commission considerations

The Commission considers that agreement between NEMMCO, the local NSP and a Metering Provider to use new metering technology is an efficient means of adopting new technology and providing incentives for innovation which should facilitate retail competition. However, the Commission is concerned that the provision is too narrow because it fails to require agreement from all those who will be directly affected by use of the new technology by the market participant and local NSP. The Commission considers therefore that agreements between NEMMCO, a market participant and the local NSP should not be permitted if they materially affect the interests of persons other than the market participant and the local NSP.

Further, the Commission notes the submission from energyAustralia and agrees that any technological change which will affect market participants generally should be the subject of consultation, preferably by means of the Code change process. The Code makes no provision for the possibility that an agreement may breach provisions of Chapter 7. It does however, allow NEMMCO to report to NECA annually on the extent to which the Code should be amended to accommodate evolving technologies. The first such report was due on 30 June 1997. Presumably, prior to any Code change resulting from the NEMMCO annual report, if an agreement failed to comply with the requirements of Chapter 7 it would be of questionable validity. This may stifle technological developments and hence, the Commission considers that NEMMCO should be able to grant an exemption from the Code.

The applicants do state that NEMMCO may grant an exemption from the metering installation standards. This provision does not, appear in Chapter 7 of the Code. The Commission recommends that a provision, including criteria which NEMMCO must consider when granting exemptions from Chapter 7 be included in the Code.

Conditions of authorisation

C12.8 Clause 7.13(a) must be amended to provide that agreements between NEMMCO, a market participant and the local NSP should not be permitted if they materially affect the interests of persons other than the market participant and the local NSP.

12.6 Other metering provisions

The Commission has considered the provisions relating to registration of metering information and meter time. Neither the applicants nor interested parties made comments on these issues. The Commission believes that these provisions do not give rise to any significant anti-competitive detriment.

13. Administrative functions

Chapter 8 describes the processes associated with the Code's administration. The chapter applies to all Code participants[88] and NECA and is a protected provision.[89] Where the provisions of Chapter 8 impose responsibilities, powers or functions upon the Commission, they are only imposed to the extent the Commission has the power to undertake, fulfil or perform them.

This section discusses each of the provisions of Chapter 8 according to the Commission's statutory criteria. However, a fuller discussion of dispute resolution and enforcement procedures, and the consequent recommendations can be found in the *NEM Access Code Draft Determination*.

13.1 Dispute Resolution

Clause 8.2 of the Code governs dispute resolution among Code participants (including NECA).

Several principles underpin the Code's dispute resolution processes. It is intended that dispute resolution under the Code:

- be governed by the market objectives and Code objectives;
- be simple, quick and inexpensive;
- preserve or enhance the disputing parties' relationship;
- take account of the skills and knowledge required for the relevant procedure;
- observe the rules of natural justice;
- place emphasis on conflict avoidance; and
- encourage resolution of disputes without formal legal representation or reliance on legal procedures (clause 8.2.1(e)).

Attempts must be made to resolve a dispute in accordance with the procedures set out in clause 8.2 before any other action is taken in relation to the dispute (clause 8.2.1(f)). This clause does not apply when a Code participant wishes to seek an urgent interlocutory injunction (clause 8.2.1(g)).[90]

The Code permits judicial review, that is, a question of law arising during the resolution of a dispute can be referred by the parties to a court of competent jurisdiction. It also allows for recourse to litigation once dispute resolution procedures have been exhausted.

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88 NEMMCO is included in the definition of Code participant in Chapter 10 of the Code.
89 The Commission has imposed conditions of authorisation that impact on the protected provision status of Chapter 8. These conditions and issues regarding protected provisions are discussed in section 6.1.
90 An interim order sought from a court to compel or prohibit conduct until final orders are made.

Issues for the Commission

The dispute resolution provisions may provide a public benefit by reducing the costs of resolving disputes and ensuring that disputes are resolved in a timely and efficient manner. In order to achieve these benefits, the Commission is concerned to ensure that the processes are timely, inexpensive, follow the rules of natural justice, do not disrupt the market and do not encourage anti-competitive agreements.

What the interested parties say

The concerns raised in submissions generally suggest there is a likelihood that disputes will arise. In this context, several submissions call for wider representation on Code administration bodies and panels including the DRP.[91] They nominate interests such as small participants, end users, participants with alternative generation and energy efficiency backgrounds and external interests such as the gas industry. In particular, the EUG argues that:

> NECA and NEMMCO who will jointly be responsible for administering the NEM need to be impartial and keep their charges to a minimum, but also have adequate resources to fulfil their responsibilities. Users must be assured of these outcomes. The new institutions need to establish effective links with end-users and involve users in their various committees and panels. ... This needs to be done for at least the Code Change Panel, Dispute Resolution Panel, Reliability Panel and Inter-regional Planning Committee.

Other participants perceive a need to monitor the effectiveness and accountability of the Code's self-regulatory processes and the Code administration bodies.[92]

The ACA notes that the dispute resolution procedures are needed but that it is preferable to obtain win/win outcomes to negotiations through the application of clear principles for such negotiations, rather than resorting to dispute resolution procedures.

What the applicants say

The applicants state that effective dispute resolution procedures must exist with recourse to an independent party to resolve and provide a binding outcome of the dispute. They note that the dispute resolution process must observe the rules of natural justice, preserve or enhance the relationship between the parties to the dispute, and ensure that the necessary skills or knowledge are available to parties to assist in resolving the dispute. They state that the Code's dispute resolution procedures reflect these principles.

Issues arising from the draft determination

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

C13.1 Chapter 8 must be amended to provide that all intending participants are covered by the dispute resolution provisions.

C13.2 NECA must, within one year of NEM commencement, conduct a review of clause 8.2. The review must consider what, if any, time limitation should be placed upon parties' rights to issue dispute notices or invoke the dispute resolution processes. The review must be conducted in accordance with the

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[91] EUG, Boral Energy, Environment Australia, Dr Hugh Outhred, the Tasmanian Government, Greenpeace.
[92] Australian Paper, BCA and the SMHEA.

Code consultation procedures and a copy of the report must be provided to the Commission.

The applicants' supplementary submission states that it was always intended for intending participants, registered with NEMMCO under the provisions of clause 2.8, to be able to use the dispute resolution procedures of the Code and the Code would be amended to clarify this position.

TransGrid supports a review of the dispute resolution process but suggests having the review two years after the market commencement to allow a sufficient case history to be compiled.

Commission considerations

A fuller discussion of these issues is to be found in section 7.3 of the *NEM Access Code Draft Determination*. A summary of the findings follows.

In a newly deregulated environment such as the NEM, disagreements, disputes and Code breaches, including disputes over the interpretation and implementation of the Code are inevitable.[93] It is therefore in the public interest that such disputes be resolved in a timely, inexpensive manner which adheres to the principles of natural justice and which causes minimal disruption to activities in the market.

The Commission considers that the Code's dispute resolution regime is largely effective and that these procedures give rise to a public benefit. Generally, the Code procedures are fair, transparent, observe the rules of natural justice and do not favour or discriminate against any person(s). Further, the Code aims to minimise the costs of disputes by mandating non-litigious dispute resolution procedures.

However, the Commission considers that the dispute resolution provisions of the Code should be accessible to all intending entrants in order to facilitate new entry. To avoid confusion and any ambiguity, the Commission requires that Chapter 8 be clarified to explicitly state that *intending participants*[94] in the wholesale market are able to use the dispute resolution provisions irrespective of whether they are yet acting as Code participants. The Commission does not consider that full fee registration of these parties is necessary. However, intending participants would need to be bound to the Code in order to use the procedures in Chapter 8 and therefore, there would need to be some form of registration for such participants.

The applicants have responded to the Commission's concerns and state it is intended that the dispute resolution procedures apply to intending participants. They accept the need for a specific provision to put beyond doubt that intending Code participants who register as such have access to the dispute resolution arrangements.

The Commission considers that the Code acts in the interests of disputing parties by including provisions that emphasise the timely resolution of disputes (ie time lines and court injunctions) but which also seek to balance procedural efficiency with a suitable regard for parties' exercise of their rights and obligations. However, the Commission is of the view that the time in which a party can issue a dispute notice, after the time the action giving rise to the

[93] Jurisdictional derogations from the dispute resolution processes are discussed in section 13.2.

[94] An intending participant is not a term defined in the Code. The Commission uses the term to refer to persons or bodies that have indicated an intention of becoming a Code participant, for all classes of participants that must register with NEMMCO under clauses 2.2 to 2.7.

dispute occurred, should be limited to ensure the efficiency of the dispute resolution procedures. The Commission considers that a review of the dispute resolution processes should be undertaken by NECA, to evaluate the dispute resolution processes, and specifically consider the need to limit the time intervening between the action giving rise to a dispute and the commencement of the dispute process. In the light of TransGrid's comments regarding the occurrence of disputes in the New South Wales electricity market such a review should be conducted and completed within two years of market commencement.

On balance, the Commission believes that, subject to the conditions set out below, the Code's dispute resolution processes are a beneficial element of the NEM arrangements as they provide an adequate means of ensuring that disputes are finally resolved in a timely manner.

Conditions of authorisation

C13.1 Chapter 8 must be amended to provide that all intending participants are covered by the dispute resolution provisions.

C13.2 Clause 8.2 must be amended to provide that NECA must, within two years of NEM commencement, conduct and complete a review of clause 8.2. The review must consider the efficacy of the dispute resolution process generally and in particular what, if any, time limitation should be placed upon parties rights to issue dispute notices or invoke the dispute resolution process. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

13.2 Code change and derogations

Procedures for changing the Code are set out in clause 8.3. Appendix C, Charts 1.1 to 1.4, diagrammatically set out the steps involved in the Code change process. Further, clause 8.4 allows Code participants or classes of participants to apply to NECA for a derogation from the Code or an extension to an existing derogation.[95] The provisions for derogating from the Code or extending an existing derogation under Chapter 8 of the Code are broadly similarly to those for Code change.

Issues for the Commission

The issue for the Commission is that the Code must explicitly recognise that as the market grows and matures there will be need for revisions of the Code to ensure that it continues to facilitate competition and does not become ossified and constraining. Thus the Code change and derogation provisions are fundamental to the public benefit arising from implementation of the Code. Moreover, the Code change and derogation processes could lessen market efficiency if consultation and accounting for different views is not sufficient.

What the interested parties say

Submissions received by the Commission raise concerns with the Code change panel (CCP), scope for consultation and the Code change process itself.

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95 A derogation is described in Chapter 10 of the Code as a 'Modification, variation or exemption to one or more provisions of the Code in relation to a Code participant according to clause 8.4.1(a).' Derogations made under Chapter 8 do not relate to or affect any derogation made under Chapter 9 of the Code.

The Tasmanian Government is concerned that Tasmanian membership of the CCP may be precluded. Dr Hugh Outhred states that the interests of small participants should be adequately represented on all committees and panels. Environment Australia advocates mandated representation of energy efficiency, alternative generation and the gas industry on the CCP. Greenpeace suggests that the CCP include representatives from the broad spectrum of renewable energy and energy efficiency industries and any member of the public should be able to participate in the process. The EUG argues that the CCP should have access to end-user and new entrant knowledge and Boral Energy contends that users should have strong representation on the CCP.

Boral Energy submits that it is critically important to ensure the process for changing the Code is clearly identified and appropriately reflects the interests of end customers and the goal of competition. Boral Energy believes the focus has to be that changes should be driven by market participants at the customer end rather than the vested interests of NSPs and generators. It contends that this needs to be positively addressed because of the diverse nature and relatively small size of users in comparison to NSPs and generators.

VPX and Hazelwood Power believe that an alternative model to the CCP should be used and that the Victorian Pool Consultative Committee model strikes a proper balance in membership which ensures that no single sector can gain competitive advantage from rule changes.

VPX considers that consultation, including discussion, is vital to a successful Code change process.

The Victorian DBs express the view that the Code change process is deficient in its total length, the lack of fast track to address aberrant behaviour, e.g. gaming, and the cumbersome process to initiate a Code change based on the number of Code participants rather than the merits of the proposed change. Hazelwood Power states it must be possible to implement change rapidly, and in a manner which keeps the participants informed.

In terms of extensions to derogations, the EUG submits that it does not believe the Code change process should consider ‘extensions’ to derogations (clause 8.3.3(b)). Dr Hugh Outhred also argues that the public as well as Code participants should be given notice of, and the opportunity to comment on, applications for derogations (clause 8.4.2).

EnergyAustralia submits it is disturbing that the Code change process is a protected provision as this raises significant questions of workability and practicality.

Delta Electricity considers the Code change procedures to be satisfactory and states that it is happy with the level of consultation proposed in the Code for issues such as changes.

What the applicants say

The applicants say that it is important to recognise that the Code is not a static document. It incorporates a process by which provisions can be changed as the market develops and experience is gained. The intent of the Code is to provide the basis for an efficient, dynamic and flexible competitive market. The transparency of the market will allow market participants, potential new entrants, end use consumers, regulators and governments to monitor the performance of the market. Should concerns arise, there is ample scope for the market arrangements to be modified to remedy any perceived weaknesses within the confines of the Code change process.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C13.3 Clause 8.3.5(d)(1) must be amended so that both Code participants and interested parties are given an opportunity to put submissions to the Code Change Panel in respect of Code changes.

CitiPower submits that the term 'interested parties' is too broad and should be defined to restrict interested parties to persons representing participants.

Commission considerations

The Commission fully recognises the importance of the Code change provisions within the Code, and supports the applicant's claim that a transparent mechanism is required to modify the Code as the market develops. However, the Commission is of the view that the Code change provisions as they currently stand are unwieldy, in particular due to the fact that it can take up to 152 days to finalise a Code change. The Commission is aware that NECA has initiated some discussion regarding the Code change provisions of Chapter 8 of the Code. Any revisions to the proposed arrangements will be assessed by the Commission at such time as a formal application regarding these amendments is received.

The Commission is satisfied that the procedures in clauses 8.3 and 8.4 provide adequate scope for consultation with Code participants and provides for interested parties to be informed of proposed Code changes. While agreeing that the views of interested parties who are not market participants should be considered, the Commission does not agree that certain interested parties should sit on the CCP. The Commission is concerned that allowing this may make the Code change process more unwieldy. However, the Commission believes that the process would be enhanced if interested parties who are notified of proposed changes, derogations or extensions were able to make submissions to the CCP.

The Commission considers that an effective Code change process must balance the need for a timely and streamlined process with the need for full consultation, including the need to take into account the views of smaller participants, alternative energy suppliers, end-users and non-market participants. As such the Commission does not accept the view put forward by CitiPower that the term 'interested parties' should be defined to restrict participation in the Code change process to those parties representing participants. Representation on the CCP needs to be broadly based in order to take into account the widest range of views, and as such the Commission, while supporting the Tasmanian Government's position that the views of Tasmania need to be heard, does not agree that this would require specific representation on the CCP by a Tasmanian representative.

Condition of authorisation

C13.3 Clause 8.3.5(d)(1) must be amended to provide that both Code participants and interested parties are given an opportunity to put submissions to the Code Change Panel in respect of Code changes.

13.3 Enforcement

Clause 8.5 of the Code and the NEL together detail the investigation and enforcement powers of NECA and the National Electricity Tribunal (Tribunal) in relation to Code breaches.

Issues for the Commission

The public benefit from implementing the NEM arrangements will derive from the effectiveness of the Code and hence, there is a need for effective compliance and enforcement mechanisms. The Commission needs to consider the costs of the enforcement process, whether it is fair, timely and efficient and whether it will effectively deter Code contraventions. Public benefit may be reduced, and entry into the market deferred, if the enforcement process is unclear, unfair, inefficient or unnecessarily expensive.

What the interested parties say

No submission in relation to this clause was received by the Commission.

What the applicants say

With respect to enforcement, the applicants note that the Code and the NEL together provide enforcement powers to ensure that the Code provisions are effective and adhered to by Code participants. They state that these provisions are given statutory force under the NEL.

Issues arising from the draft determination

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

C13.4 The regulations referred to in clause 8.5.5(a) which set out the nature of sanctions which may be imposed under the Code, must be finalised prior to NEM commencement.

C13.5 NECA must, using the Code consultation procedures, develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5.1. The guidelines and conditions must also set out those circumstances in which a Code participant is to bear the cost of providing the information sought by NECA, irrespective of whether a breach of the Code has occurred.

The applicants state in their supplementary submission to the Commission that a draft of the National Electricity Regulations will be made publicly available and it is intended that the regulations will be in place well before market commencement. They also note that the National Electricity Law and the Code will have the effect that NECA will bear the cost of investigations where an investigation does not result in a penalty or Tribunal proceedings.

TransGrid supports the development of guidelines regarding NECA's investigation powers under clause 8.5.1 of the Code, but suggest these guidelines are not necessary prior to market commencement.

Commission considerations

In assessing the Code's enforcement mechanisms, the Commission has identified a number of shortcomings, and these are fully discussed in section 7.4 of the *NEM Access Code Draft Determination*.

Together, section 9 of the National Electricity Law and the regulations prescribe the Code provisions as Class A, B or C. Due to the difference between the civil and criminal standards of proof, the imposition of civil as opposed to criminal penalties for Code breaches should increase the likelihood of penalties being imposed. The Commission considers that this should provide an incentive for Code participants to comply with the Code.

Individually the shortcomings identified in the Code's enforcement mechanisms are unlikely to bring into question the enforceability of the Code. Nevertheless collectively they create uncertainty of procedure and outcomes and therefore are likely to detract from the effectiveness of the provisions. In particular, until the regulations classifying the Code provisions are adopted, the Commission cannot properly assess the balance between the public benefit, and anti-competitive detriment of the penalties and enforcement provisions.

This is because, in the absence of more information the Commission is concerned that:

- delay in publishing the regulations will add to the uncertainty as to how effectively the Code will operate in practice;
- the range of penalties may be limited and inflexible in meeting the diverse circumstances of different breaches; and
- penalties may be inappropriately severe or lenient in response to particular breaches.

Consequently, the Commission's authorisation of the Code is conditional upon these regulations being finalised pursuant to the regulation making powers in Part 4 of the NEL before the national market commences.

The Commission recognises that NECA is, to some extent, accountable for its conduct through the NEL, the Code and the common law. However, these provisions do not guarantee that the right to natural justice will be observed when NECA conducts its investigations. Therefore, there is a degree of uncertainty in the process which raises the potential for litigation from aggrieved participants.

Further, the Commission is concerned that under clause 8.5.1(c) costs must be met by the person being investigated or preparing documentation or reports. This would appear to be the case, even where there is no breach established, unless NECA or the Tribunal determines otherwise. The potential that a Code participant will pay the costs of any action taken by NECA under clause 8.5.1 may reduce any incentives on NECA not to order investigations or the preparation of documents of reports unless it has reasonable grounds for doing so. A further concern is the disadvantage which may be suffered by a Code participant who may not be in breach of the Code.

The Commission is of the view that NECA must, using the Code consultation procedures, develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5.1. The guidelines and conditions must set out those matters which NECA must have regard to or be satisfied as to, prior to the exercise of its powers and also set out those circumstances in which, notwithstanding that no breach of the Code by a Code participant is subsequently found to have occurred, that Code participant is to bear the cost of providing the information sought by NECA.

Condition of authorisation

C13.4 Clause 8.5.5 must be amended to provide that operation of the Code shall not commence until the Regulations relating to sanctions referred to in clause 8.5.5(a) have been made.

C13.5 Clause 8.5.1 must be amended to provide that NECA must, using the Code consultation procedures, develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5.1. The guidelines and conditions must also set out those circumstances in which a Code participant is to bear the cost of providing the information sought by NECA, irrespective of whether a breach of the Code has occurred.

13.4 Confidentiality

Confidential information is defined in Chapter 10 and dealt with under clause 8.6. As a general principle, each Code participant[96] must use all reasonable endeavours to keep confidential any confidential information which comes into its possession or control or of which it becomes aware (clause 8.6.1(a)).

In particular, a Code participant must not disclose confidential information to any person except as permitted by the Code, must only use or reproduce confidential information for the purpose for which it was disclosed or another purposes contemplated by the Code, and must not permit unauthorised persons to have access to confidential information. Each Code participant must also ensure that any person to whom it discloses confidential information observes the provisions of clause 8.6.

Issues for the Commission

These provisions may be anti-competitive because they give rise to an information asymmetry which may impact on current participants while also impacting on a person's ability to enter the market. However, this anti-competitive risk must be weighed against the public benefit of providing adequate protection for genuine commercial-in-confidence information, particularly where releasing such information may reduce incentives for innovation.

What the interested parties say

The Victorian DBs state 'simply claiming that any information relating to the business of the Code participant is confidential or commercially sensitive is not sufficient. Under the Code information is not intrinsically confidential.'

The submission contends that the definition in Chapter 10 includes only information provided to a Code participant (which, by definition, does not include NECA, the DRP and the CCP) and which is stated by the Code, NEMMCO, or NECA to be confidential.

The submission states that is not satisfactory that for the purposes of the Code and NEL:

- that any claim of confidentiality must await the decision of NEMMCO or NECA;
- that pending any such decision the information is not confidential;
- that Code participants indemnify NECA and NEMMCO against claims for breach of confidentiality (clause 8.6.5) and that NECA 'is in no way liable for publishing or disclosing' (clause 8.7.3(b));

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96 Which includes NECA and any panel or other body established by NECA under the Code. See clause 8.6.4.

- that any such decision is not reviewable, e.g. (clause 8.7.3); and
- that information provided to NECA and any panel or body established by NECA under the Code is not regarded per se in the Glossary as confidential.

The submission puts a preferred position which is:

- that material may be claimed to be confidential information by a Code participant; and
- that the definitions in Chapter 10 be amended to read as follows:

> *confidential information*
>
> In relation to a Code participant, information which is or has been provided by or to that Code participant under or in connection with this Code, or which is stated under this Code or by NEMMCO or NECA to be confidential information or otherwise confidential or commercially sensitive, or information which is derived from any such information.

All such material will then be dealt with as if it were confidential by all Code participants and under clause 8.6.4 by NECA and any panel or body established by NECA subject to:

- the exceptions at clause 8.6.2; and
- specific provisions which allow NECA to decide to publish generally or to a limited extent any such information, always provided that any such decision is reviewable.

What the applicants say

The applicants make no submission in relation to this clause.

Commission considerations

The Commission considers that the confidentiality provisions allow adequate protection for commercial-in-confidence information, particularly where releasing such information would reduce incentives for innovation.

The Code exceptions to confidentiality of information, particularly those which require disclosure to ensure safety (for example, system security) and allow disclosure for the purposes of market efficiency (for example, release of quantity-bid data under the consent exception) are considered reasonable at this time. The Commission considers therefore that the public benefit of releasing this type of information outweighs any potential anti-competitive detriments.

Contrary to the Victorian DBs submission, the Commission notes that clause 8.6.4 expressly includes NECA and its bodies and panels and thus information provided to NECA by a Code participant would be protected. Further, under clause 8.2.10(c), the DRP is subject to clause 8.6 unless clause 8.7.3(b) applies.[97] The definition in Chapter 10 also makes provision for the protection of commercially sensitive information.

The Victorian DBs contend that information provided to other panels or bodies established by NECA would not be regarded per se in the Glossary as confidential. The Commission notes that pursuant to clause 8.6.6 NEMMCO must develop principles for protecting information it acquires as a result of its functions from use or access which is contrary to the Code. The Commission considers that such principles should be extended to all NEM bodies and panels.

The Commission recognises that the need for Code participants' information to remain confidential where relevant must be balanced against the needs of regulators, the market operator, Code participants and the public generally to have access to information. The Commission would therefore encourage NEMMCO, NECA and other bodies and panels to balance the need for open decision-making with any confidentiality claims in a manner similar to that set out in s. 89 of the TPA.[98] In the case of information and submissions given to NECA, NEMMCO and other Code panels and bodies, information which is required to be released under the Code should only be used for the purposes for which it was disclosed unless the person making the submission consents to that information being otherwise released.

Under clause 8.6.5, Code participants are to indemnify NECA and NEMMCO against claims for breach of confidentiality whereas under clause 8.7.3(b) NECA is in no way liable for publishing and disclosing information under clause 8.7. This issue is considered in relation to liability in section 6.2 above and in relation to monitoring and reporting in section 13.5 below. Further, the Victorian DBs also note that a decision made by NECA pursuant to the provisions in clause 8.7.3(b) is not a reviewable decision. This is considered below in section 13.5.

Condition of authorisation

C13.6 Clause 8.6.6 must be amended to provide that NEMMCO must also develop and implement policies concerning the protection, dissemination and use of information by each of the bodies and panels established under the Code.

13.5 Monitoring and reporting

Under clause 8.7, NECA is required to monitor compliance with the Code and use reasonable endeavours to ensure the effectiveness of the Code in accordance with its objectives.

Issues for the Commission

The Commission needs to consider whether compliance with clause 8.7 could restrict entry to the market and reduce the benefits arising from the NEM. Further the costs of complying with the clause may give rise to a financial barrier to entry to the market. Further concern is

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[97] See below, section 13.1. Under clause 8.7.3(b) NECA may release the information if it believes it must do so to satisfy its reporting obligations. NECA must, in releasing such information, as far as practicable, protect the confidentiality of that information.

[98] Under this section a person may request that a submission to the Commission, or part thereof, remain confidential and thus be excluded from the public register. If the Commission refuses a request to exclude a document from the public register, that document may be returned to the person making the request for confidentiality and will not be considered in the decision-making process.

whether clause 8.7 substantially lessens competition by unevenly applying reporting standards and requirements, offsetting public benefits.

What the interested parties say

A number of submissions raised concerns with clause 8.7.

VPX is concerned that NECA's functions are inadequate and that NEMMCO should have a role in market monitoring. VPX submits that NECA's monitoring functions are too tightly defined and are unlikely to afford sufficient protection to market participants and end customers. VPX argues that NECA is not the organisation best placed to undertake monitoring of market behaviour. It states that a formal monitoring role for NEMMCO should be established to determine whether market rules need to be tightened, or whether there is evidence of any market participant acting in an anti-competitive manner. VPX also suggests that if monitoring uncovers anti-competitive behaviour, then it would be NECA's responsibility to refer the matter to the Commission.

The Industry Commission notes that the National Grid Company in the England/Wales market introduced a system of reporting poor behaviour by suppliers. It suggests that this practice works to discourage strategic bidding and has the advantage of reducing the potential monitoring costs to the grid company. The Industry Commission suggests a similar system could be adopted by NEMMCO.

The Victorian DBs note that NECA 'is in no way liable for publishing or disclosing' any information under this clause 8.7 (clause 8.7.3(b)). They note that any such decision is not reviewable (clause 8.7.3). The Victorian DBs submit that NECA or any panel or body established by NECA be subject to specific provisions which allow NECA to decide to publish generally or to a limited extent any such information, always provided that any such decision is reviewable.

What the applicants say

The applicants state that clause 8.7.2(d) allows NECA to establish additional or more onerous reporting requirements and monitoring standards which do not apply to all Code participants. They suggest that such provisions could be considered to be exclusionary provisions, exclusive dealing provisions or provisions substantially lessening competition.

They argue, however, that it is not the intention of the clause that NECA should exercise this discretion in a way which would give a competitive advantage to one party over another. Its purpose is to enable NECA to take into account the various circumstances that might dictate a more rigid or onerous reporting arrangement for participants in one set of circumstances which would not apply to participants whose circumstances are different. The applicants submit that the provision makes it clear that some judgement would be expected of NECA in determining special reporting and monitoring arrangements without being required to apply the same arrangements universally to all participants with the general increase in overall industry compliance costs. They contend that the public benefit in NECA having and exercising reasonable discretion in determining arrangements which do not have to apply universally to all Code participants is in the containment of costs of Code participation.

Issues arising from the draft determination

The issue of market monitoring was raised in the context of the Commission's condition of authorisation C8.11, regarding monitoring of market participants behaviour. See sections 8.5

and 8.11 for further discussion. No issues were raised regarding NECA's role in monitoring compliance with the Code.

Commission considerations

Clause 8.7 may give rise to a financial barrier to entry due to the costs to participants of complying with its provisions and costs to NECA which may increase pool fees. Despite the potential anti-competitive detriments of clause 8.7, the Commission considers that it gives rise to an offsetting public benefit by ensuring that the Code is assessed in a comprehensive manner and further, that its provisions are being complied with by participants.

While the Commission accepts the need for some flexibility in the reporting requirements imposed by NECA, and notes that any decision by NECA to impose additional or more onerous reporting requirements will be reviewable, it notes that NECA's discretion may need to be fettered in some way. The Commission is of the view that the Code should include criteria which NECA must follow when deciding whether to impose additional or more onerous reporting requirements on a Code participant. Such criteria could be formulated in conjunction with the reporting requirements to be established by NECA pursuant to clause 8.7.3.

The Commission notes the submission from the Victorian DBs in relation to the release of confidential information by NECA pursuant to clause 8.7.3(b). The Commission considers that NECA must notify a Code participant of any decision to publish that Code participant's confidential information. The Commission also recommends that any such decision be reviewable prior to publication in an urgent application to the Tribunal by the Code participant who owns the confidential information. The Commission believes such a provision is necessary given NECA's limited liability and the potential for the release of such information to have significant adverse effects on a Code participant's business.

The Commission also notes the submissions of VPX and the Industry Commission. It agrees monitoring of market outcomes in relation to anti-competitive behaviour must be done. The Commission has imposed a condition of authorisation on NECA to ensure such monitoring takes place. This issue is discussed in sections 8.5 and 8.11.

Conditions of authorisation

C13.7 The Code must be amended to provide that NECA must, using Code consultation procedures, develop and implement guidelines and conditions with respect to the exercise of its powers pursuant to clause 8.7.2(g). The guidelines and conditions must set out the matters which NECA must have regard to prior to deciding the allocation of costs of any additional compliance monitoring.

C13.8 Clause 8.7.3(b) must be amended to provide that NECA must, as soon as practicable, notify a Code participant of any decision to publish that Code participant's confidential information. Any such decision must be reviewable prior to publication in an urgent application to the National Electricity Tribunal by the Code participant who owns the confidential information.

13.6 Reliability Panel

NECA must establish a Reliability Panel as soon as practicable to:

- monitor, review and report on power system reliability;
- determine power system security and reliability standards;
- determine guidelines for NEMMCO with respect to issuing directions and contracting for reserves; and
- report to NECA and the jurisdictions on power system reliability matters (clause 8.8).

The Reliability Panel's processes are set out diagrammatically in Appendix C, Chart 2.

Issues for the Commission

The Reliability Panel, as the body responsible for matters relating to system security, is essential to the public benefits that arise from the Code. In order to ensure this public benefit, the Commission must be satisfied that, in conducting reviews and determining reliability standards, the Reliability Panel is fair and efficient. These provisions may be anti-competitive because they may give rise to information asymetries between those party to the Reliability Panel's deliberations and those that are not.

What the interested parties say

Submissions received by the Commission were concerned with panel representation and the role of the Reliability Panel vis à vis the reserve trader.[99]

The Victorian DBs submit that the role of the Reliability Panel in setting the overriding guidelines for the reserve trader will have an important influence on the manner in which reserve capacity is valued and subsequently purchased in the market place. They suggest the true worth of this product ought to be a customer based decision, that the appropriate venue for this input by market customers is within the Panel and they recommend a compulsory distribution business member on the Panel.

The EUG considers that the independence of the Reliability Panel must be assured and involve users.

Environment Australia submits that the Reliability Panel's task is to ensure reliability of electricity supply, rather than meeting end customers' electricity needs, and argues that the Code exhibits a bias in favour of electricity supply, at the expense of other energy services such as distributed resources and gas. Environment Australia contends that reliability could provide a vehicle for traditional electricity supply interests to unfairly tilt the playing field toward traditional energy sources. Greenpeace agrees and submits that all energy supply and energy efficiency industries should be represented. Dr Hugh Outhred also stresses that demand side participants and small generators should be adequately represented.

The Tasmanian Government submits that Tasmania needs to be assured of a representative voice on the Reliability Panel as reliability standards set for the interconnected system may have significant implications for the industry in Tasmania. It contends that an important principle for the Government is that decisions should not be made on behalf of prospective member jurisdictions or participants in those jurisdictions without their direct involvement.

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[99] The reserve trader is discussed in section 9.2.

SEQEB states that the description of the functions of the Reliability Panel indicate that it is targeted at reliability of the generation and transmission systems. However, by using the term 'power system' it includes (perhaps inadvertently) the effects of distribution systems. The reliability panel should perhaps be explicitly limited to the generation and transmission networks.

Issues arising from the draft determination

Yallourn Energy states in its submission that the Reliability Panel and NEMMCO should include demand side responses when considering system reliability.

The Australian Consumers' Association raises the issue of representation on the Reliability Panel, and asks that the Commission impose a condition of authorisation such that the Reliability Panel must include a member nominated by the Australian Consumers' Association representing small consumers and public interest. It notes that the Australian Consumers' Association has representatives on the Licence Compliance Advisory Board in New South Wales.

Commission considerations

This section focuses on the processes of the Reliability Panel, while system security concerns are discussed in section 9.2.

The Commission notes the submission from the Tasmanian Government that it be assured of a representative voice on the Reliability Panel. The Reliability Panel unlike, for example, the Boards of NECA and NEMMCO, does not have jurisdictional representation as such. However, panel members will be appointed with reference to participating jurisdictions.

The Commission agrees with submissions arguing that the Reliability Panel should be representative of views from across the electricity industry. This is important as not all of the matters that the Reliability Panel is responsible for will be subject to the Code change provisions, and a more representative Reliability Panel would be expected to reflect the views of all of those with an interest in the reliable supply of electricity. The Commission therefore recommends that the Code nominate a broad range of interests, including those of retailers, end-users and alternative generation sources, from which members of the Reliability Panel may be selected by NECA. The Code should also include provisions to ensure that these interests will be represented. This will assist in balancing the process so that it is not biased (or seen to be biased) in favour of any sectoral interests.

The Commission is aware that the Reliability Panel that has been established does not include representatives from end use consumer groups, and considers that this over-sight will detract from the effectiveness of the Reliability Panel. The Commission recommends that the membership of the Reliability Panel be expanded to include a representative of small end use consumers.

The Commission acknowledges that there will be a number of intending participants (in all classes of participants) who will have an interest in system security and reliability. Hence, it considers that the provisions relating to consultations by the Reliability Panel must be amended to allow intending participants to put submissions to the Reliability Panel and attend any hearings held by the panel, in the same manner as recommended for the dispute resolution and Code change procedures.[100]

Further, any Code changes recommended by the Reliability Panel will have to be brought to the Commission for consideration if they may breach the TPA or alter the authorisation. This should provide additional opportunities for public consultations. The Commission suggests that any guidelines determined by the Reliability Panel be consistent with the TPA and the Code's pro-competitive intentions.

In its present form, the Code is not clear about whether a report or determination of the Reliability Panel will be publicly available. The Commission notes that a Code change recommended by the Reliability Panel will be exposed to a public consultation process. However, the Commission also considers that all reports and determinations of the Reliability Panel must be publicly available, subject to the confidentiality provisions in clause 8.6.

SEQEB submits that the Code be clarified such that 'power system' is limited to the generation and transmission networks. The Commission agrees with the submission but considers that distribution systems may need to be taken into account by the Reliability Panel insofar as their operation effects overall system security. Clause 8.8 should therefore be amended to expressly state that the Reliability Panel is not concerned with the effects of distribution systems except insofar as they affect the reliability of the transmission system.

The processes of the Reliability Panel, in conducting reviews and reaching determinations, are generally timely and efficient. Further, the procedures set out in clause 8.8, should prove to be inexpensive, particularly given the public benefits which will result from the work of the Reliability Panel.

Conditions of authorisation

C13.9 Clause 8.8.3 must be amended to provide that intending participants, as well as Code participants, are entitled to make submissions and attend any of the Reliability Panel's hearings.

C13.10 Clause 8.8.3 must be amended to provide that NECA, within 10 days of receiving the written report of the Reliability Panel must, subject to the applicable confidentiality provisions, make the report publicly available.

C13.11 Clause 8.8.1 must be amended to provide that, the Reliability Panel, in undertaking its review pursuant to clause 8.8.3(b) and in preparing its report, considering reliability of the power system, must limit its considerations to the transmission networks, considering other factors such as generation, demand side response and distribution networks only insofar as they affect the overall system security.

13.7 Code consultation procedures

Clause 8.9 sets out the Code consultation procedures and these are diagrammatically represented in Appendix C, Chart 3. The Code requires use of the Code consultation procedures where this is expressly stated.[101]

[100] See sections 13.1 and 13.2.

Issues for the Commission

Effective consultation procedures will increase the public benefit of the proposed NEM arrangements.

What the interested parties say

Macquarie Generation points out that the Code leaves a large number of issues unresolved and gives the responsibility to NEMMCO and NECA for resolution of these issues. This submission notes that generally the Code requires consultation with participants to resolve these issues but no formal process is outlined and the obligation on NEMMCO to take into account the impact on participants is not clear.

Macquarie Generation believes this situation, together with the changes to regulatory responsibility that will occur during the implementation of the market, create significant commercial risks for participants. It contends that some formal mechanism should be established to ensure that all participants' interests can be protected. This mechanism should provide for some form of appeal to an independent body.

What the applicants say

The applicants do not explicitly discuss competitive effects of the Code consultation procedures in their submission.

Commission considerations

While recognising the value of the Code consultation procedures, the Commission considers there is a danger that they will fail to take account of the views of intending participants. The Commission considers that clause 8.9 should be amended such that all intending participants in the class of participants nominated by the relevant Code provisions should also be consulted. It is also recommended that the glossary in Chapter 10 be amended to reflect this.

A consulting party must not make the decision or determination in relation to which the Code consultation procedures apply until the consulting party has completed all the procedures set out in clause 8.9. The Commission considers that under the Code as submitted, the means by which this provision may be enforced are ambiguous and, as the use of consultation procedures is integral to the Code and to numerous conditions of authorisation, the Commission considers the position must be made certain. It is therefore a condition of this authorisation that the Code clearly state the consequences of failure to comply with clause 8.9.

The Commission notes the concerns of Macquarie Generation. However, the Commission is of the view that the Code consultation procedures, if amended in accordance with the Commission's recommendations, will constitute a formal process which places an obligation on the consulting party to take into account the impact on participants by ensuring that all participants' interests are taken into account. Further, any matters which result in changes to the Code will be the subject of consultation processes which aim to take into account the views of all Code participants and interested parties.

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[101] For example, in determining matters relating to prudential requirements, determination of the dispatch algorithm, the STFM and IRHs.

Conditions of authorisation

C13.12 Clause 8.9(a)(1) must be amended to provide that intending participants in the class of participants nominated by the relevant Code provisions are consulted.

C13.13 Clause 8.9(b) must be amended by adding at the end thereof:
'Any decision or determination purportedly made where the consulting party has failed to comply with clause 8.9 when required to do so, is, if made by NECA or NEMMCO, a reviewable decision and is in any case of no force or effect until the requirements of clause 8.9 have been substantially complied with.'

14. Transitional arrangements

Chapter 9 contains the jurisdictional derogations of the participating jurisdictions (except Queensland) and its provisions prevail over all other chapters of the Code. [102]

Jurisdictional derogations are:

- those provisions of the other chapters of the Code which shall not apply either in whole or part to particular Code participants or potential Code participants or others in relation to its jurisdiction for a fixed or indeterminate period;
- any provisions which, for the jurisdiction, substitute for those provisions which are not to apply; and
- provisions applicable only to that participating jurisdiction.

The purpose of jurisdictional derogations is to enable Code participants to effect an orderly transition to the provisions of the Code from the current State and Territory based arrangements. They also provide specific exemptions from the Code for pre-existing arrangements which the jurisdictions have determined must continue beyond a specific transition period (clause 9.1.1(d)).

As part of its assessment of the Code, the Commission examined the derogations, focussing on those derogations which raise significant concerns.

14.1 General issues

Clauses 8.3 and 8.4 (Code change and derogations) do not apply to Chapter 9.[103] A change to jurisdictional derogations can only be made by the Minister of the relevant jurisdiction. That Minister must give notice to and consult with the corresponding Minister of each other participating jurisdiction about any proposed change within a reasonable time prior to seeking approval for the change from the Commission.

Issues for the Commission

The varying transition periods and different derogations in the participating jurisdictions may have anti-competitive effects, by providing a competitive advantage to participants in their respective jurisdictions. Furthermore, the operation of the derogations, by limiting the universal application of the Code, will impact on the overall public benefits which the Code is be expected to deliver.

What the interested parties say

The SMHEA, Dr Hugh Outhred, Australian Paper, and Boral Energy contend that an efficient market could be jeopardised by Chapter 9, particularly if its provisions continue beyond the year 2000.

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[102] Queensland submitted provisions for State-based wholesale trading of electricity for authorisation in October 1997. These arrangements will apply until Queensland joins the NEM.

[103] See section 13.3.

The SMHEA argues that jurisdictional derogations should not be accepted if they substantially alter the market or affect the operation of the market outside their jurisdiction, e.g. Victoria's proposal for price caps and a Victorian region based on the state boundaries. They say that these substantially lessen competition and cause barriers to inter-state trade.

The EUG is concerned that the derogations provided for in the Code may compromise the objective of a competitive national market without clear public benefits to offset any anti-competitive impact. It recognises that some adjustment to new circumstances may be required to avoid shifts that are too dramatic and that some transitional measures by jurisdictions are probably inevitable. It also believes that if the derogations do not comply with the terms of the National Competition Policy, then the National Competition Council (NCC) must take this into account in terms of the 'competition payments' for the jurisdiction concerned. As a general rule, the EUG would support the use of financial payments to jurisdictions rather than derogations where there is a clear offsetting public benefit — this avoids market distortions and makes the cost of the measures more transparent.

The Victorian DBs claim that a forced or rushed modification to arrangements that predate the Code will have a deleterious impact upon the Victorian electricity industry and the creation of the NEM. They acknowledge that some of the Victorian derogations extend beyond 31 December 2000 but note that this is to allow the provisions of the Tariff Order, which relate to distribution pricing, to apply beyond the transitional period. They say that the purchase of the DBs was predicated on these arrangements, and subsequent business planning has been based on the Tariff Order having continuing effect. They believe commercial certainty is a necessary starting point from which to work towards the NEM and altering this would result in price shocks and other market disturbances, which would retard the orderly progression to harmonised market conditions and the NEM.

What the applicants say

The applicants state that the purpose of Chapter 9 is to define clearly which parts of the Code are not to apply and for how long this will continue. They say that the Chapter 9 derogations provide continuity and a transition from State arrangements and price determinations established before the national market. In some cases arrangements were determined well before details and impacts of the Code were known. They also state that in providing a transitional period, the Chapter 9 derogations have regard to the legitimate business interests of providers who were given undertakings in regard to jurisdictional based arrangements, where changes to those arrangements would have a significant and deleterious commercial impact.

Commission considerations

Chapter 9 is to be distinguished from individual derogations which may be sought by any Code participant under clause 8.4. The jurisdictional derogations apply to Code participants because of exemptions specified by a jurisdiction, not by Code participants. As a result, the Commission is concerned that participants in certain jurisdictions may gain an unfair advantage through jurisdictional derogations.

The Commission notes that most jurisdictional derogations are for the 'transitional' period ending either on 1 July 1999 or 31 December 2000 and accepts that, given the NEM is expected to start on 29 March 1998, a transitional period of around five years, ending no later than 31 December 2002 is not excessive. Thus, any competitive benefits conferred on Code participants from such jurisdictional derogations will be short lived. However, derogations that go beyond a transitional period are of concern to the Commission as they may prolong anti-competitive arrangements or delay the benefits of an integrated NEM..

Chapter 9 is not subject to the Chapter 8 Code change process which requires consultation with Code participants.[104] However, amendments or additions to Chapter 9 by a jurisdiction necessitate consultation with other jurisdictions and are otherwise subject to 'approval' by the Commission. Further, where derogations are submitted for authorisation, the Commission's processes will include consultations with Code participants and interested parties. Hence, the Commission considers it will not be possible for jurisdictions to unilaterally add derogations to benefit participants in that jurisdiction.

The Commission is also concerned about the use of the word 'approved' (in clause 9.1.1(e)) in the context of the Commission's role. The applicants have not indicated whether this connotes an authorisation, acceptance of an access undertaking, or both.

For the avoidance of doubt, the Commission's decisions regarding authorisation do not extend to Chapter 9, Part E — Transitional Arrangements for Queensland.

14.2 Regulation of transmission pricing in Victoria

Amendments to the Victorian derogations were received by the Commission on 23 July 1997. These amendments were proposed against the background of the Victorian Government's decision to privatise PowerNet Victoria (PNV), the owner and operator of Victoria's transmission network. The successful bidder for PNV, GPU PowerNet Pty Ltd, was announced 12 October 1997. The amendments to the Victorian derogations require the regulator of transmission networks (to be the Commission from 1 January 2001), to continue to apply the relevant provisions of the Victorian regulatory arrangements (ie. those governed by the *Electricity Industry Act 1993* (EI Act), *The Office of the Regulator General Act* 1*994* and the Tariff Order), for so long as any part of those provisions continues to apply. The Commission, as regulator, would only be able to perform its functions under the Code to the extent that they are not inconsistent with the Victorian regulatory arrangements.

The amendments to the Tariff Order extend the current regulatory methodology for PNV to the year 2002, five years from the expected time of sale of PNV. The current efficiency 'X' factor (of 1.79 per cent) is left unchanged until 1 January 2001, there is no revaluing of the PNV assets, and the specified augmentation regime is left in place until its expiry in the year 2000. For the period 1 January 2001 to 31 December 2002, a new X factor (of 11 per cent) is applied. The Victorian Government would also impose licence fees for the years 1998 to 2002, which will recoup a total of $190m.

At the end of 2002, a regulatory review will be undertaken to set the price path for PNV for the next five years. Under the Tariff Order proposals this involves the regulator applying CPI–X regulation, the application of a single X factor for the five year regulatory period, allowing PNV to retain a portion of excess revenues achieved, limiting the value of X to ensure the regulator cannot recoup excess returns achieved in the current regulatory period in the next regulatory period, use of the capital asset pricing model (CAPM) to estimate the weighted average cost of capital (WACC), use of the 1994 Optimised Depreciation Replacement Cost (ODRC) asset valuation, prohibiting re-optimisation of the asset base, and

[104] See section 13.2.

setting out a range of matters that the regulator must have regard to in future revenue determinations.

The Tariff Order also imposes some limitations upon the regulator for regulatory reviews for the period beyond 1 January 2008.

Issues for the Commission

A consideration for the Commission is that transmission pricing regulation is a major factor in the effectiveness of the access regime, and hence the level of competition in the generation and retail sectors of the ESI.

Further the Commission is concerned with the possible precedential effect of the amended Victorian derogation and Tariff Order in influencing derogations from other jurisdictions participating in the NEM, as well as national access regimes and regulatory arrangements applying in other industries, such as gas.

Another issue is the effect of binding the regulator to the proposed regulatory framework, for a period of 10 years or beyond, and its relationship to the 'regulatory certainty' that Victoria argues is necessary in the sale of PNV assets.

The Commission also needs to consider the nature of the transition path to the NEM arrangements implicit in the proposals. This is heightened by the precedence the Victorian arrangements will take over the Code in perpetuity, unless specifically ruled out by the Code arrangements.

A further issue arises regarding the legal framework surrounding the regulatory regime and the mechanism by which the Commission (as regulator) can enforce the provisions of the Victorian Tariff Order and licensing arrangements.

What the interested parties say

The Commission has received 15 submissions specifically dealing with the amendments to Victoria's derogations received on 23 July 1997.

Precedent effect

SMHEA raises concerns over the possible precedent effect of the derogation, stating that other jurisdictions may also make such derogations. SMHEA also claims that the derogation will prolong the 'rail gauge' problems within the NEM beyond the agreed transition period.

Colin Taylor questions the legality and degree of public interest in regulating the transmission assets in Victoria on a different basis to other states, and notes that "it must be anticipated that accepting the proposal is likely to set a precedence for different regulatory criteria to be applied on a State by State basis." He notes that this effect could also apply to other industries, such as gas.

The South Australian Government argues that the PNV derogations will distort transmission prices in Victoria relative to other jurisdictions. It adds that the effect of the Victorian derogations will be to extend the period that transmission prices in jurisdictions will remain subject to jurisdictional policies rather than being set according to a national approach.

The Queensland Government states that it has concerns over the possible inter-state effects, the implications for investment and the precedent which is being established by the PNV derogations. It argues that the extension of the transition period to 2007 fails to meet either the letter of the COAG agreements or the spirit of them.

The EUG states it is most concerned that the authorisation of significant derogations for extended periods in the area of transmission pricing, where there is an expectation the Code will be applied, will undermine the national market. It argues that other jurisdictions could use the derogation to detract from the NEM and National Competition Policy.

Capral Aluminium (Capral) and BHP also raise concerns over the precedent effect of authorising this derogation.

Regulatory flexibility

ACTEW raises concerns about regulatory flexibility and the Victorian proposals, which impinge upon the ability of the regulator to improve network pricing methods, for the period up to 2012. Capral and SMHEA point out the derogation pre-empts the NECA review, undermining the value of the review, and prevents the regulator from applying improved transmission pricing arrangements, for the purpose of immediate windfall gain.

BHP states that in conflict with the Code provisions, the decision on transmission tariffs has been made by the Victorian Government, rather than a regulatory body, and has been made with no customer involvement and only limited consultation. BHP asks that the Commission ensures the derogation is not incorporated into the Code unless it provides for full consultation processes and information disclosure requirements, for the present period and future reviews. BHP also stresses that a review period should be no more than five years.

TransGrid asks that the Commission ensures the asset valuation methodology, depreciation rules and other revenue determining parameters adopted in the Victorian derogation can be readily developed into a uniform set of national parameters. TransGrid claims the assertion that PNV will be provided with a return on its assets approximately equal to the return earned by TransGrid is difficult to substantiate without full disclosure of both entities' financial parameters, and further points out that IPART applied a degree of judgement to the valuation of TransGrid's assets, as well as relying on other financial indicators in its pricing determination.

CitiPower, while supporting the overall objectives of the derogations, has reservations about the highly mechanistic and prescriptive approach proposed. It notes that the proposals are not inconsistent with the Code, but has concerns to the extent which the regulator will be precluded from applying alternative models of regulation which may emerge in the future. In particular CitiPower suggests that transmission networks could be better regulated by reference to general economic indicators with a reliance on bypass to ensure economic efficiency.

CitiPower, while supporting the objective of 'fair sharing of efficiency gains' and the concept of incentive based regulation does not support the locking in of the mechanism, as proposed in the derogation.

The EUG argues that the derogation provides for too long a period before PNV's assets are revalued. It claims that the Commission should have an opportunity to review PNV's asset valuation when it assumes regulatory responsibility, particularly bearing in mind concerns that PNV's revenue cap is already too high.

Australian Paper argues that it is 'at a loss' to understand the extent and duration of the derogations. It states it is concerned by the request to lock in this new tariff structure for 10–15 years as errors may be locked in. Australian Paper is strongly of the view that regulatory reviews should not exceed five years. It further argues that the decision to have a longer period between reviews has no validity unless designed to give revenue stability for a prospective asset purchaser. Australian Paper claims this is clearly inappropriate.

CitiPower has reservations regarding the derogations extending 'well beyond what might reasonably be described as a transition period'. Capral agrees that a transition period may be necessary, but states it should be kept as short as possible, and that derogations should not extend beyond five years.

Other issues

SMHEA points out that the management of transmission assets will impact across borders, and such a derogation can distort the energy market.

Colin Taylor also notes that the impact of the proposals cannot be quarantined to Victoria, as the cost reflective component of transmission pricing impacts upon all NEM participants to some degree. He states that it would be preferable for a common transmission network regulation approach, with a common end date, to apply to all States in the NEM.

The South Australian Government considers that as long as transmission prices in different jurisdictions are subject to separate jurisdictional policies, there should be a requirement that there be no cross border cash flows for transmission pricing.

The Queensland Government is concerned that the costs of this derogation be quarantined to Victorian customers. It claims that any transfer into other States would have implications for generation investment and energy sourcing decisions. The Queensland Government has concerns over the Victorian Government's reluctance to apply the Optimal Deprival Value (ODV) asset valuation, arguing that it is unclear why there should be a delay in revaluing the assets to well into the next decade. This, it argues, may introduce distortions between TUOS charges and generation investment.

The Queensland Government concludes that the PNV derogation should include a shorter sunset, a revaluation of assets to establish a more market oriented price for transmission to ensure investment decisions are not distorted, and a quarantining of the effects to Victoria if neither of these elements can be accommodated.

BHP notes the licence fee arrangements, in place to prevent windfall gains of $190m to PNV, imply substantial scope for estimation error in the setting of transmission prices in the period up to 2002. It states that there is a failure in the regulatory system whereby customers are required to pay charges based upon pre-existing costings, although revised costings have been used to devise the new charging arrangements, including the extraction of the licence fee. Arrangements should be included to pass through the $190m in cost saving to end users. Given that the Maximum Uniform Tariff does not apply to a large portion of the Victorian market, BHP believes the Tariff Order should be amended to allow a reduction in transmission charges and DBs to immediately pass through the cost savings to end users.

Capral also argues that the $190m in special levies from PNV should flow through to end customers.

Boral Energy raises concerns over the imposition of a flat licence fee, stating that such a fee does not equitably meet the objective of limiting PNV's ability to extract monopoly rents from the market. Boral Energy states that the licence fees are non-cost reflective, and will distort price signals to the market, in particular disadvantaging projects such as embedded generation. BHP also has concerns regarding the treatment of embedded generation in the Tariff Order, and suggests it needs to be amended, along similar lines to the IPART proposals for the treatment of embedded generation, to address the need to share the benefits of embedded generation and establish guidelines for this process.

BHP reiterates earlier comments regarding information disclosure, and the need for the Code to provide for review of information disclosure provisions in the light of experience. In particular, a reassessment would be required where customer participation in the revenue capping process is ineffective. BHP suggests that the Commission review PNV's asset base, given the importance of the asset base and the fact it is locked in until 2007.

A further concern raised by BHP is the return on capital allowed to PNV, and benchmarking the return to the Australian Gas Light (AGL) level in New South Wales. BHP is concerned that access charging in the gas industry limits the extent to which competition will develop in that industry, but also established a poor precedent for other infrastructure sectors. BHP suggests that the Commission should review the return implicit in the PNV pricing arrangements, and use international benchmarks as a guide.

CitiPower argues that there is no strong reason evident for protecting the asset values from review until 2007, and notes the proposed approach will extend the complications and disadvantages faced by cogeneration in relation to transmission charges.

Hazelwood Power argues that the combination of the Code and the Tariff Order still provide no commercial drivers to enable proper allocation of risk on a negotiated basis. It notes that unless the accountability of PNV for the performance of its assets in delivering competitive energy to the market is strongly emphasised immediately, the impending privatisation of PNV is likely to make the development of a firm access regime difficult or impossible in the future.

Australian Paper supports the concept of a CPI–X approach, but argues that the fact the proposed X is such a large figure implies the current revenue cap is too high and should be reduced now. It adds that original asset valuation for PNV was obviously incorrect, a point supported by the Victorian Government decision to reduce the asset value but claim the resulting revenue surplus as a licence fee. The fact that PNV charges are higher than need be, Australian Paper claims, is due to the lack of a reality test. It recommends that the Code should require benchmarking against international equivalents.

The consultant's view

With funding from the Victorian Government, the Commission contracted NERA to evaluate and provide commentary on the general regulatory framework to apply to electricity transmission in Victoria. This summary is taken from NERA's report to the Commission an edited version of which will be made publicly available.

Precedent effect

Consistent with many of the participants, NERA observes that Victoria's proposals will impose State based regulatory arrangements until at least 2007, thereby delaying the introduction of nationally uniform transmission regulation. Further, the Victorian regime will effectively operate in perpetuity, unless the Code specifically rules out the mechanisms used in the Victorian instruments (eg ODRC valuation and the glide path), which leaves little prospect of truly uniform national transmission regulation.

NERA indicated that the Victorian proposals pre-empt the NECA pricing review and NERA also stated that other jurisdictions are unlikely to accept proposals from the NECA review which would lead to customers in one State paying for transmission services in another State, unless the basis for regulation is the same. NERA concluded that the likely effect of the Victorian proposals is abandonment of a national transmission pricing regulation regime.

Regulatory flexibility

In its report NERA stated that the proposed Victorian methodology prescribes certain elements which limits the regulator's flexibility. NERA states that in using the glide path methodology it will be important to distinguish between the extent to which future determinations of allowed revenue will be influenced by efficiencies achieved, as opposed to exogenous influences or to decisions which belong to the regulator. Where above normal returns are due to good fortune or any other exogenous parameters, it would be more efficient for price to be allowed to reflect costs more quickly (ie P_0 adjustment). Therefore the case for mandating the use of a pure glide path needs to establish that the likelihood of the good fortune/exogenous factors occurring is small and/or their impact is inconsequential. NERA states that a more mainstream view is that while a perfect analysis is never possible, the potential magnitude of these factors may make them too important to ignore by mandating a specific form of glide path. This position is reflected in the submissions received from Capral, SMHEA, CitiPower and Australian Paper.

A further consideration is that the main opportunities for 'gaming' in reporting of past costs is in relation to whether expenditure is reported as either operating or capital, the extent to which costs are taken into account in one year as opposed to the next, and cost allocation/transfer pricing between regulated and unregulated parts of the business. The BHP submission to the Commission strongly emphasised the likelihood of information inaccuracies impacting upon any determination made by a regulator. While NERA recognises the practical limitations to the extent and longevity of 'gaming' by these means, the existence of a glide path increases the risk and inevitability of making incorrect judgements which are part of the price-cap determination process. Based on UK empirical evidence, NERA also points out that the greatest risk of getting a price determination wrong is at the time of privatisation.

NERA also notes that the recontracting risk must be considered in the political environment and a mandated glide path may increase the regulatory re-contracting risk, if locked in profits were publicly perceived to be too high.

With regard to asset valuation, NERA echoed many of the participants' concerns when it stated that it is important to recognise just how crucial the capital cost-related assumptions are. Aside from whether or not the proposals will deliver higher prices than desirable from an economic efficiency perspective, the sensitivity of PNV's required revenue to these regulatory parameters significantly increases the risk of locking in inappropriate returns under the mandated glide path methodology.

NERA notes that prescribing the application of the ODRC approach can also set up incentives for over investment (same as under rate of return regulation). Further, the mandated application of the ODRC approach appears to allocate some stranded asset risk to PNV. NERA raises this concern as PNV does not have control of network augmentation nor of the intensity of network use — the main sources of asset stranding risk. As key network decisions are made by VPX, the cost/risk of asset stranding should ideally be reflected in the decisions which VPX makes. It would be sensible to be clarify the risk allocation of asset stranding between VPX and PNV.

Third, NERA expressed the view that specifying the CAPM, to determine the allowed rate of return for PNV, though current best practice, is unnecessarily restrictive given increasing uncertainty about its validity. Although the proposed approach is not uncommon for asset intensive, regulated industries, NERA stressed the importance of the capital cost assumptions. In particular, while NERA considered that the conceptual basis for the ODRC valuation is sound, it felt that the practical application of the ODRC valuation results in an upward bias and that the ODRC estimate for PNV is overstated.

Moreover, NERA questioned several of the key assumptions in determining the WACC, including:

- Does the asset beta reflect the particularly low risk nature of PNV's business, relative to other network utilities (ie if revenue is protected by the regulator)?

- Should the risk free rate be determined on today's rate (which is what bidders will actually pay) rather than on a long term average?

- Does imputation credit utilisation raise consistency issues with respect to foreign owners compared to local owners?

- Is the 60 per cent gearing assumption low given PNV's risk profile compared with other utilities?

NERA's conclusion was that the concepts applied and the assumptions reached at each step in the WACC calculation have erred towards higher rather than lower estimates.

Furthermore, from 1998 onwards the proposed revenue determination does not require any real reduction in operating and maintenance costs. In relation to capital investment the capital spending plans have not been developed on a needs basis which is a fundamental requirement of good utility regulation. NERA states the evidence suggests that the allowed level of capital expenditure is unlikely to bear any relation to that which an efficient operator would look to incur.

In summary, NERA's conclusions regarding the proposed Victorian arrangements were in line with many of the views of participants, questioning whether the PNV regulatory proposals:

- are overly prescriptive;

- allow for subtleties and judgements which are required; and

- will achieve the objectives of making customers better off and reducing the likelihood of regulatory recontracting.

NERA also points out that preventing developments in the application of principles, for example by over-specifying a particular methodology, on the back of enhanced knowledge and experience, can be counter productive. It must be recognised that consistent application of principles will not always result in the same answer or revenue determination methodology. For example NERA supports the use of 'glide path' as a regulatory tool, but does not support mandating a specific form of glide path for use at all future price determinations, as the Victorian proposals have done.

Other issues

The issue of locational signals and possible impact upon competition in other markets was raised in a number of submissions. NERA's paper argues that competition in related markets will be affected by both the overall transmission revenue, and by the structure of transmission prices. Therefore to the extent that location-based transmission pricing is not possible, competition in the generation sector will continue to be distorted. As is the case at present, remote generators will not face the true costs of their location decision.

NERA's analysis also suggests that PNV's total revenue will be higher than necessary to cover efficient costs (including a return to the owner). This will provide incentives for users to avoid the costs of the transmission network (e.g. through uneconomic duplication, bypass and increased incentive for alternatives to networks such as greater generation capacity).

What the applicants say

The applicants claim that the proposed amendments to the regulation of transmission pricing were not designed to enhance the value of PNV. Victoria's view is that the introduction of private ownership is the best driver towards efficiency and consumer focus. The changes to the Tariff Order will result in a two per cent reduction in electricity prices to consumers over the period 2001 to 2002. The changes do not alter the competitive elements of the transmission sector, such as the contestable nature of augmentations to the transmission system in Victoria. The changes in fact enhance the contestable nature of the transmission sector (through the abolition of the list of prescribed augmentations).

In addition, these changes do not purport to extend the period for which the ORG will be responsible for regulation of transmission pricing. The Victorian Government remains committed to transferring to the Commission regulatory responsibility for transmission pricing from 1 January 2001, in accordance with the present version of the Code.

The changes will mean that the Commission will be required to apply the principles set out in the Tariff Order, rather than Chapter 6 of the Code, in its price determination which will have effect up until 2007.

The applicants claim that the principles and methodologies for regulating transmission pricing specified in the Tariff Order are not inconsistent with the principles set out in the Code but rather specify in more detail how the principles in the Code are to be applied in Victoria and deal with certain other matters not addressed in the Code.

The applicants state that the arrangements will limit the ability of PNV to extract monopoly rent, through the imposition of an X factor of 11 per cent in 2001 and 2002, and the extraction of $190m in licence fees for the years from 1998 to 2001. The Victorian Government's advisers have determined that the arrangements should provide PNV with a return on assets which is approximately equal to the return being earned by TransGrid in New South Wales and is comparable with IPART's recent determination of AGL's return on assets. The applicants argue that while PNV's return on assets will be approximately equal to TransGrid's, PNV is in fact exposed to higher risks than TransGrid as a result of the VPX/PNV split in Victoria which results in PNV having no control over network investment and planning functions.

Beyond 2002, the criteria for determining transmission pricing will allow PNV to earn a reasonable rate of return, based on a WACC formulation and having regard to levels of risk assumed by PNV and international and inter-state benchmarks.

The applicants also argue that the 'CPI–X' approach to regulation which provides an incentive for the regulated business to be efficient (including optimising between asset investment and operating expenditure) and requires gains from efficiencies to be shared with consumers in the long run. The proposed Tariff Order amendments set out the 'belts and braces' of implementing this approach and are designed to reduce doubt and avoid ambiguity.

The applicants state that to maximise the incentives to achieve efficiencies it is necessary to define how the Regulator will require the sharing of benefits from efficiency gains between PNV and its customers. The proposed amendments to the Tariff Order expressly provide for a fair sharing of efficiency benefits between PNV and its customers (similar to the 'glide path' method used in the UK). They state that this methodology has the greatest potential to maximise the level of efficiency gains and the speed at which such gains are achieved, delivering sustained benefits to consumers over time.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C14.1 Clause 9.8 must be amended to provide that the transmission pricing regulation derogations must end on or before 31 December 2002.

The Victorian Government's submission indicated that they are prepared to amend their derogation in response to the Commission's condition of authorisation.

Commission considerations

Precedent effect

The Commission had significant concerns regarding the likely impact of this Victorian derogation on the implementation of the NEM. These concerns have been reflected in a number of the submissions from interested parties and also raised by NERA. As stated in section 14.1 of this final determination the Commission considers a transition period of no more than five years to be adequate.

The Commission does not consider the Victorian derogation can truly be considered a transitional arrangement as it allows for the Tariff Order to be applied in perpetuity, unless the Code specifically rules out the proposed mechanisms. In this sense the proposed derogation would make it difficult to fulfil the various commitments made during the 1990s through COAG:

> "Agreed to the principles for a national competitive electricity industry of a uniform approach to network pricing …[where] this applies to such things as cost reflective and uniform pricing methodologies."

The Commission notes and in general agrees with the concerns raised by interested parties in their submissions regarding the impact of this derogation on the implementation of uniform transmission pricing regulation in the NEM, and in other industries such as gas. The Commission considers there is a substantial risk that in authorising the proposed Victorian arrangements other jurisdictions may then come forward with long term derogations for transmission pricing, or other aspects of the Code, with respect to their own State based arrangements. Indeed, Queensland, in their draft derogations provided to the Commission, explicitly state that they will only comply with the provisions of clause 6.2.1(a)(5) of the Code (commencement of transmission pricing regulation) if all other participating jurisdictions also comply with that clause.

The implication of non-uniform transmission price regulations is that the NEM will effectively operate as linked State markets, and unless the State based arrangements are amended to include locational signals, continuing distortions will flow into the generation sector of the industry.

Transitional arrangement

The Commission's concerns regarding the proposed arrangements are magnified by the period for which the derogation is to apply and the lack of a clearly specified end date. The arrangements can be considered as dealing with several distinct periods, for example up until the end of 2000, 2001 to the end of 2002, 2003 until the end of 2007 and 2008 and beyond.

The Commission has already stated that it considers a transition period of around five years, until 31 December 2002, to be adequate in terms of the need for the jurisdictions to make incremental adjustments to the full NEM arrangements. Derogations that extend beyond 31 December 2002 will generally not be accepted by the Commission unless the applicants demonstrate a clear net public benefit, a clear end point and a clear transition path to the NEM arrangements.

The applicants claim that the derogations will provide a benefit through the introduction of regulatory certainty for the buyers of PNV's assets, without introducing any detriment to consumers. Counter to this, interested parties have pointed out that whilst agreeing with the need for regulatory certainty, in order to maximise the sale price received for PNV, the period for which the arrangements extend (and the detail of the arrangements) may enable the owners of PNV to extract monopoly rents at the expense of consumers. Further, it was submitted that the period of regulatory certainty proposed was far in excess of that given to other buyers of newly privatised assets, both in Victoria and overseas.

The Commission's consultants, NERA, also pointed out that the long time period involved may in fact increase regulatory uncertainty, if there were political or public perceptions of the returns generated under the arrangements being too high. Therefore, while the Commission agrees that there is some measure of public benefit in removing unnecessary uncertainty for potential buyers, it does not agree that the proposed arrangements have achieved that goal, nor that it is necessary for uncertainty to be removed to the extent proposed.

The Commission also notes that the effective end date of the derogation is the time at which the NEM arrangements, as specified in the Code, specifically contradict the proposed

Victorian arrangements. Clearly this neither sets out a defined transition path nor an end date for the derogation.

Regulatory flexibility

Victoria's transitional transmission regulatory arrangements, specified in Chapter 9 of the Code, and also in the terms of the Tariff Order, prescribe the pricing methodology to be applied by the Regulator through to 31 December 2007. Additionally, the Tariff Order seeks to impose on the Regulator a number of ongoing restrictions with respect to reviewing the revenue control arrangements which take effect after 31 December 2007 (Tariff Order clause 3.7.1).

Capral and SMHEA point out that the Victorian derogation pre-empts the NECA review of network pricing, and by prescribing the methodologies to be applied, restricts the Regulator from applying possible improvements in pricing methodologies that may be developed in the future. As such the Commission is concerned that the arrangements will prevent the Regulator from applying best practice regulation to the transmission network in Victoria.

The Commission also queries the magnitude of the perceived regulatory risk, and doubts the effectiveness of the Victorian arrangements in managing this risk. The applicants have not demonstrated the need for prescribing the regulatory model to the extent that has been done and, as noted by NERA in their draft report, the arrangements may in fact have the opposite effect. When placed in a political context there is increased risk of regulatory recontracting to the extent that the returns are perceived to be excessive.

The Commission is aware of the need for the price regulation to include some incentives to drive efficiency gains, and hence the need to allow the regulated business to keep the benefit of some of those efficiency gains. This is balanced by the need to limit the ability of monopoly businesses to extract monopoly rents from users of their facilities. However, the Commission is not convinced that the glide path methodology as prescribed under the Victorian arrangements is the best option for achieving the balance of maximising incentives for efficiency gains and maximising consumer welfare.

Similarly, the locking in of asset values until the end of 2007 is of concern because it is unlikely that the use of the network will remain such that the valuation would still be correct, in either eight years (2002) or 13 years (2007) from the original. This issue was raised by CitiPower and Australian Paper in their submissions. Changes in use, population shifts, development of embedded generation, network bypass, augmentations and competing interconnectors may all occur in such time frames, and will all impact upon the valuation of the PNV asset. The Commission will not accept a derogation which prevents the Commission from taking the option of revaluing the assets at the time the Commission takes over as Regulator.

The Commission has other concerns regarding the proposed regulatory arrangements, including the assessment of the riskiness of the business as reflected in the WACC and implied rate of return on assets, the level of capital investment under the arrangements, and the depreciation arrangements. The risk associated with the PNV assets impacts upon the pricing outcomes, but is not well defined especially with regard to the impact of the separation between network planning and network ownership. For example this separation may reduce risk by providing PNV a guaranteed return on augmentations dictated by VPX, although the applicants present a contrary claim.

The elements of the proposed regulatory arrangements are inter-related and the Commission is concerned with the overall impact, as well as the components of the arrangements. To this extent it may be possible to recast the proposals such that a trade off is effected between the degree of regulatory certainty regarding the methodology and the parameters used in regulatory reviews.

In light of the above assessment and the Commission's view that transitional arrangements should not extend beyond five years, the Commission has decided to accept the Victorian transmission pricing derogation provided that the derogations regarding the regulation of transmission pricing in Victoria have an explicit end date on or before 31 December 2002. This means that the proposed asset valuation lock-in would cease at that time and price regulation of PNV would be subject to the provisions of the Code.

The 31 December 2002 cut off date will not affect the equalisation adjustment which phases out gradually until 30 June 2020 as it reflects pre-existing regulatory policies which underpinned the privatisation of the Victorian DBs.

The Commission notes that the Victorian Government is prepared to accept the Commission's condition of authorisation. An amended Electricity Supply Industry Tariff Order (the Tariff Order) will reflect this earlier cut off date.

Condition of authorisation

C14.1 Clause 9.8 must be amended to provide that the transmission pricing regulation derogations must end on or before 31 December 2002.

14.3 Transitional arrangements for intra-regional loss factors and network pricing in South Australia

Amendments to the South Australian transitional arrangements for calculation of loss factors (clauses 9.27.1 and 9.27.2) and network service pricing arrangements (clauses 9.29.2(i) and (j)), extending the derogations until 31 December 2010, were received by the Commission on 21 April 1997.

Loss factors

In the period up to 31 December 2000, all intra-regional loss factors to apply to market customers for the transmission of electricity through a transmission network situated in South Australia will be calculated by a government body.

In determining intra-regional loss factors, the relevant government body must use its reasonable endeavours to ensure that the forecast aggregate financial outcomes for all the market customers to which the intra-regional loss factors are to apply are the same as the forecast aggregate financial outcomes as if there were no derogations. The government body must use its reasonable endeavours to use the same data in making the above forecasts that would have been used in determining intra-regional loss factors under Chapter 3.

The intra-regional loss factors which will be applied to market customers for the transmission of electricity through a transmission network in South Australia after 31 December 2000 will be determined by NEMMCO in accordance with the clause 9.27 and clause 3.6.2. [105]

Further provisions apply to distribution loss factors. After 31 December 2000, a factor describing the weighted average electricity loss incurred in the distribution of electricity between all of the transmission network connection points situated within a distribution zone will be applied. The South Australian Government is to determine the boundaries of a distribution zone.

Network pricing

Under clause 9.29, the procedures for regulation of transmission pricing in South Australia will be specified by the South Australian Government and the Jurisdictional Regulator will be responsible for the administration, enforcement and regulation of prices within the regulation procedures. Aggregate annual revenue requirements and related price variations will be determined in accordance with South Australia's own transition policies and will be based on CPI–X escalation for existing assets (as specified in Chapter 6) and the requirements for approved new network investment. These provisions apply until 31 December 2000.

If there is more than one DNSP in South Australia, the South Australian Government may use measures to manage distribution network revenue requirements including asset revaluations or equalisation payments.

After 31 December 2000, the TUOS charges for each transmission network connection point situated within a transmission zone[106] will be determined by:

- aggregating the relevant revenue requirements (determined in accordance with Chapter 6) for all the transmission network connection points within that Transmission Zone;
- aggregating the related electricity quantities transmitted to all the transmission network connection points within that Transmission Zone; and
- calculating an average TUOS charge.

Thus, the TUOS charges for each transmission network connection point situated within a Transmission Zone will be the same. These arrangements will cease to apply after December 2010.

Issues for the Commission

These provisions could amount to an arrangement that has the purpose, or has or is likely to have the effect, of fixing or controlling the price of electricity traded in the wholesale market.

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[105] Clause 3.6.2 states that NEMMCO must calculate intra-regional loss factors for each transmission network connection point for each financial year based on annually revised data.

[106] A transmission zone is defined in clause 9.25.2 as 'an area fixed by the South Australian Government prior to 31 December 2000 comprising the specific section of the South Australian transmission network, and all transmission network connection points, situated within that area'.

To the extent that the national arrangements in clause 3.6 provide efficient signals, this derogation may be anti-competitive in that it results in price distortions between final consumers, impacting on market efficiency and locational signals.

Also, the provisions could have the effect of advantaging Code participants in South Australia over Code participants in other jurisdictions, affecting inter-state trade and competition. The extension of the transitional arrangements to the year 2010 may increase the anti-competitive detriment of these arrangements.

What the interested parties say

The South Australian Government states that the proposed methodology uses the averaging of loss factors within zones to reduce the range of variations in price for different locations. It claims without these amended derogations, the Code provisions would result in significant price increases for some rural customers. With these derogations applying, it calculates that the resulting increase for most (primarily urban) customers will be small (less than one per cent for most customers in the Adelaide metropolitan area). It believes that there is no evidence of tangible specific benefits arising from more cost reflective pricing for rural customers. It states that it is significant that the current economic climate has placed considerable financial pressures on the rural community.

The South Australian Government argues that potential anti-competitive detriment is mainly limited to the possible impact on the behaviour of remote customers, relating to competition between grid based electricity supply and alternative energy sources, and possible longer term investment decisions. It claims that these implications are likely to be minor.

Further, it does not regard it as equitable to introduce substantial changes from existing arrangements which would fall disproportionately on a vulnerable sector of the community without some offsetting mechanisms which will allow all sectors of the community to share the expected benefits of reform. It states that there is no evidence to substantiate the argument that the resource allocation implications of more cost reflective electricity pricing for rural customers would provide benefits to justify significantly higher prices for them, when the overall impact is expected to be lower electricity prices in general.

The South Australian Government argues it is relatively easy to implement and explain the averaging approach and it avoids the significant costs of establishing and administering a system of explicit payments. In addition, the minor distortion in the pricing signals for those customers who will source the cross subsidy is probably of less significance than the effects of approximations involved in the Code provisions for determining loss factors in the first place.

It also claims that the public benefit arguments applying to the network pricing derogations are substantially the same as those applying to the loss factor derogations, and it is difficult to identify any specific competitive detriment from the arrangements.

The ACA believes that the South Australian Government's discussion and analysis of the public benefits and anti-competitive effects in relation to the amended derogations is inadequate and 'bordering on contemptuous'. The ACA argues that postage stamping of transmission pricing distorts economic signals and creates a barrier to entry for cogeneration and embedded generation. Further, it says this will lead to incorrect and inappropriate investment which will result in higher electricity prices than would otherwise be the case. The ACA states that the anti-competitive features far outweigh the cost of implementing and administering Community Service Obligations (CSOs) as is being done in some other jurisdictions. The ACA also states that an appropriate assessment cannot be made until the details of the access and pricing arrangements can be seen and is concerned that they may contain a multitude of anti-competitive features such as bundled tariffs, constraints on bypass, network augmentation issues and other barriers to entry.

The ACA firmly believes that any transitional arrangements should be in place for the shortest possible time (no later than 2000) and details of the tariff and access arrangements need to be available so that affected parties are able to make an informed assessment. The NECA transmission pricing review is seen as being extremely important to addressing a number of the network pricing issues that create barriers to cogeneration and embedded generation. The ACA contends that extended derogations, like those proposed, act to reduce the relevance of the NECA review and defeat competition policy objectives.

The EUG is firmly opposed to the South Australian derogation, because it is clearly inconsistent with the cost reflective network pricing objectives of the NEM, the objectives for the national market and Code itself, transmission pricing derogations from other jurisdictions and the Competition Principles Agreement of the National Competition Policy. It states that the impact of the derogation will be to prolong inefficient cross subsidies (of which no impact is given) in transmission pricing in South Australia, which is inconsistent with a competitive market place and in all probability will severely blunt locational signals for electricity producers and end users. It believes that the derogation is anti-competitive and notes that the application provides an unconvincing case for offsetting public benefits. No evidence is given of the economic costs of delaying cost reflective transmission pricing. It believes that a better approach would be for South Australia to provide transparent assistance to the ‘small number’ of customers involved through CSOs and fails to see how administrative costs for a small number of customers could be a sufficient reason not to do so.

The EUG argues that the amended derogation is likely to have a significant impact in distorting locational signals for power supply and use, and will also impact on electricity trade into and out of South Australia. Industry is likely to carry most of the costs of these proposals which also detract from a national market. The EUG supports an approach to loss factors which takes greater account of marginal network losses. It notes that, unlike the proposed New South Wales and Victorian derogations on loss factors which at least provide for review by NECA and apply for relatively short periods, the South Australian derogations do not mention the possibility of NECA involvement and apply until 2010.

The Department of Primary Industries and Energy (DPIE) states that the concept of a Transmission Zone as defined could have undesirable outcomes and it would be more acceptable if a minimum number of zones was specified in the derogation due to the effect of uniform transmission pricing across large areas. It also states that the arrangements are a significant threat to transparent pricing outcomes and ensuring clear locational signals to market participants. Also, investment decisions and grid augmentation proposals may not come forward under this arrangement, or it could result in a misallocation of resources.

The DPIE argues that it is difficult to relate this derogation to COAG agreements to introduce a fully competitive electricity market by 1 July 1999 and acceptance of such derogations might be considered inconsistent with the preconditions that States must meet to qualify for the second tranche competition dividends. DPIE believes it would be inappropriate for the Commission to endorse special arrangements for the treatment of intra-regional losses in South Australia to apply through to 2010. This is particularly the case before NECA has undertaken the review of the transmission and distribution pricing principles contained in the Code.

What the applicants say

Loss factors

The applicants state that the primary purpose of the amended South Australian derogation for loss factors is to avoid substantial electricity price increases for a relatively small number of customers that are not reasonably close to the main transmission backbone. It is considered that such increases would have substantial adverse economic and social impacts on these customers without any offsetting competitive benefits.

It is argued that because of limited realistic alternatives for those customers, the impact of the proposed South Australian derogation amendment on resource use is likely to be small. In addition, the proposed South Australian derogation amendment will impact only on prices for the bulk of customers within South Australia which are likely to be less than variations arising from the normal commercial operation of the national market.

The applicants contend that, while it would be theoretically feasible to achieve similar outcomes through arrangements for explicit payments, the payments would vary depending on specific locational and customer details. The establishment and ongoing administration costs would be significant and the proposed South Australian derogation amendment provides the desired outcomes in a pragmatic, cost-effective way without any perceived significant anti-competitive detriments.

Network pricing

In relation to the original NEM application, the applicants argue that South Australia's transmission network service pricing derogation is broadly consistent with the provisions of Chapter 6 and that the other provisions in clause 9.29 provide for the use of measures to manage the introduction of network prices during the transition period which are similar to those used by the other participating jurisdictions. They say these are necessary to ensure that price impacts on customers will be manageable. Further, they state that South Australia submits that its transitional arrangements relating to transmission network service pricing will not have any identifiable impacts on competition in generation or retailing.

South Australia's transmission network pricing derogations apply for the transitional period up until 31 December 2000 as well as longer term derogations which last for the duration of the access code up until 31 December 2010. The stated objectives of the transitional derogations are to allow the South Australian Government:

- to make decisions in applying the Code's general principles; and
- to ensure the detailed transmission pricing arrangements are consistent with its policy for customer electricity prices.

More specifically, the transitional derogations allow the State government to:

- determine the initial detailed pricing structure for the transmission network;

- use various measures to manage the network revenue requirements in accordance with its own transition policies;
- and apply their own specific criteria and methodologies (including the Code's general principles for asset valuation and WACC) to determine a maximum aggregate annual revenue requirement.

The derogations also provide for dividing the State into a number of zones, with the government determining average TUOS prices for each zone.

In the longer term, the derogations provide for uniform transmission pricing in each of a number of zones instead of the individual connection point pricing otherwise required by the Code. Accordingly, an average TUOS charge within each transmission zone will be calculated, based on an aggregate of the:

- relevant revenue for all the transmission network connection points within that transmission zone; and
- related electricity quantities transmitted to all the transmission network connection points within that transmission zone.

The applicants state that these amendments were introduced to manage the impact of cost reflective transmission pricing on customers at the extremity of the network. The applicant states that South Australia's aim is to avoid substantial electricity price increases for these customers, as such increases would have substantial adverse economic and social impacts without any offsetting competitive benefits.

The applicant notes that while it would be possible to achieve similar outcomes through arrangements for explicit payments, the administrative costs of such a system would be significant and the payments would vary depending on location and customer details. They state that the amended derogation provides the desired outcomes in a pragmatic, cost-effective way and is similar to the distribution pricing arrangements. While South Australia proposes to continue this approach after the transition period, there is no provision for the continued use of other mechanisms such as equalisation payments. The applicant states that the impact of the proposed amendment is intended to apply only to the allocation of costs for the existing network and not to costs where new loads involve network augmentation.

Issues arising from the draft determination

The Commission's draft determination imposed conditions of authorisation as follows:

C14.2 Clauses 9.27.1 and 9.27.2 must be amended to specify that the derogation ends on or before 31 December 2002.

C14.3 Clause 9.29.2(j) must be amended to specify that the derogation ends on or before 31 December 2002.

The BCA/EWG submission indicates their support for the Commission's conditions relating to these derogations. BCA/EWG also advises that a new \$2/MWh levy had been imposed on transmission prices in South Australia and argues that the level and distribution of network prices will blur appropriate pricing signals. The South Australian Government has indicated that it will amend its derogations in response to the conditions of authorisation imposed by the Commission.

Commission considerations

Loss factors

As discussed in section 8.3, accurate calculation of losses provides economically efficient locational price signals to ensure the most economic outcome in terms of location of generation and load on the grid. Losses are also important in ensuring that new investment is appropriate and that the right balance is achieved between investment in generation, demand side measures and/or the transmission network.

The Commission considers that differences between jurisdictions in determining transmission intra-regional losses could distort inter-state trade. In addition, alternative methods of determining both transmission intra-regional losses and distribution losses could create price distortions between consumers within each region, thus reducing competition. At present the jurisdictions cross-subsidise from urban to rural on the basis of losses and this derogation would extend that practice.

The Commission accepts that there may be a public benefit from avoiding price shocks to rural customers, and notes the South Australian Government's discussion on rural hardship in the current economic climate. However, it is not clear that this public benefit will outweigh the anti-competitive effects of cross subsidisation in favour of rural customers for the 12 years beyond the market commencement. The Commission also notes that the South Australian Government could alleviate any financial hardship to the rural customers through the application of CSOs. The Commission is concerned that the derogation for the determination of loss factors in South Australia is extended until 2010 and that NECA does not have a role for this extended period.

The proposed derogation is also significantly different to the principles outlined in the Code, and represents a major departure from the NEM arrangements.

After considering the arguments put forward by both the applicants and the interested parties, the Commission remains unconvinced of the need for this derogation to apply to the year 2010. In the Commission's view this derogation would be likely to affect the market to a great extent, distorting locational signals, and the public benefit accruing to rural customers is not sufficient to outweigh the overall anti-competitive detriment. Therefore, the Commission will impose a condition of authorisation to limit the transitional period for which this derogation applies, such that the derogation ends on or before 31 December 2002.

Network pricing

Consistent with its assessment of the NEM transmission pricing regime, the Commission accepts the merit of pricing approaches which attempt to balance the competing efficiency and equity objectives; in particular in the context of avoiding a price shock to certain consumers and thereby allowing a broad range of consumers to share in the benefits of reform. To this extent, the Commission accepts the South Australian pricing derogations on the basis that they attempt to balance the interests of users and the wider public over the transitional period ending on 31 December 2000.

However, the Commission has a number of concerns with South Australia's proposed network pricing derogations which run from 2000 to 2010. In particular, the proposed derogation's use of average network prices is a further move away from cost reflective network prices which, in the case of the uniform NEM arrangements, the Commission believes are already significantly flawed in terms of the likely efficiency signals it will provide.

Moreover, the longer term derogations cannot be reasonably be described as transitional as they institute a non-uniform approach to transmission network pricing for the duration of the access code. In this sense the proposed derogation appears to be a deviation from the various commitments made during the 1990s:

> Agreed to the principles for a national competitive electricity industry of a uniform approach to network pricing …[where] this applies to such things as cost reflective and uniform pricing methodologies.[107]

Indeed, the later COAG commitments emphasised the cost reflective and uniform recovery of the transmission networks' fixed costs whereas 'distribution system pricing could be calculated using a greater degree of averaging'.[108]

Consequently, the Commission is unwilling to accept the proposed South Australian derogation as it is a move away from a cost reflective and uniform approach to transmission network pricing. More significantly, however, the Commission does not accept that the proposed derogation is transitional and is concerned that long term derogations may establish a precedent and encourage other jurisdictions to develop non-uniform and long term derogations. The Commission believes that if such an eventuality were to occur, it would erode many of the benefits of having a single wholesale electricity market in southern and eastern Australia.

In reaching this conclusion, the Commission acknowledges the benefit in avoiding a sudden price shock for rural and remote consumers. Ideally the Commission favours a transparent CSO. However, the Commission has accepted the arrangements for transmission pricing and intra-regional loss factors provided they end on or before 31 December 2002.

Responsibility for determining price outcomes is placed in the hands of the jurisdictional regulators and in most circumstances this regulatory approach to controlling monopoly power is sufficient. However, this will not always be the case and conflicts of interest may arise when a government is both the regulator and owner of the utility. This potential conflict of interest will be most acute in those circumstances where the regulator is not at arms length from governments and where government budgets have come to rely on the dividend stream from publicly owned utilities. This issue is discussed in more detail in the *NEM Access Code Draft Determination*. As a consequence of this possible conflict of interest arising the Commission recommends that the South Australian Jurisdictional Regulator be independent of the South Australian Government.

[107] COAG Communique, 25 February 1994, Hobart.
[108] COAG Communique, 19 August 1994, Darwin.

Conditions of authorisation

C14.2 Clauses 9.27.1 and 9.27.2 must be amended to specify that the derogation ends on or before 31 December 2002.

C14.3 Clause 9.29.2(j) must be amended to specify that the derogation ends on or before 31 December 2002.

14.4 Technical standards (Victoria and South Australia)

Victoria has derogated from the technical standards and processes relating to NSPs and generators. The obligations of VPX and PNV are varied and certain network augmentation procedures do not apply to the augmentations specified in Part C of Schedule 5 of the Tariff Order. Specific derogations relating to plant technical characteristics are dealt with in Schedule 9A3.

Under clause 9.28, South Australia derogates from the technical standards in Chapter 5. For South Australian facilities existing at the time of market commencement, exemptions may be sought from NEMMCO where material departures from the Code are reasonably expected. Alteration of the arrangements for facilities is to be negotiated and agreed by affected Code participants. Exemptions are to be sought, in accordance with the Code provisions, within 12 months of the date on which South Australia first participates in any part of the market. South Australia reserves the right to seek further exemptions from NEMMCO for existing power stations if they are unable to meet Code requirements and those exemptions will not result in system damage. Specific derogations relating to plant technical characteristics are dealt with in Schedule 9D1. These provisions will apply until there are corresponding Code changes which deliver equivalent outcomes to the satisfaction of the South Australian Government.

What the interested parties say

The ACA, the BCA and the EUG criticise the derogations from the Code's technical standards on the grounds that the exemption of older generators (typically coal fired plant) from the technical standards will create a competitive advantage compared to cogeneration plants and new entrants who must comply with the technical provisions in Chapter 5.

The consultant's view

Western Power suggests that the provisions in the Victorian derogations (clause 9.7.5 and Schedule 9A3) may confer some advantage on existing participants or adversely affect system security. Further, clause 9.7.6 and Tables 7 and 8 of the Schedule 9A3 which relate to protection systems that impact on system security and asynchronous operation respectively, may also be of some concern. Western Power states that without knowing the specific circumstances of each derogation, its reasonableness cannot be determined.

What the applicants say

With respect to technical requirements for NSPs, the applicants state that the derogations are included to clarify VPX's and PNV's obligations under the Code, and reflect the existing technical design limitations of the transmission network.

The applicants argue that the Victorian derogations on technical requirements for generating units in the Code have been prepared on the basis of what would be expected of a generating unit in today's environment. The applicants contend that these are to take into account known technical and design limitations of generating units and other facilities. They say it is appropriate to deal with these now to:

- recognise that the likely cost of requiring plant modification to meet the standards in the Code exceeds any potential gains in terms of system security or operation of the market. In most cases, the system has operated for many years safely and efficiently without the relevant plant complying with the requirement;
- provide information to market participants and others at Code commencement about the known technical limitations of plant; and
- provide certainty by including the derogations at Code commencement rather than requiring use of the Code derogation process.

The applicants argue that the derogations in Schedule 9A3 are based on rules which were prepared following a detailed due diligence exercise in Victoria after the restructuring of the industry and were approved by the Regulator–General.

The applicants state the primary purpose of the South Australian derogations is to ensure that the Code requirements relating to network connection are not applied to Code participants retrospectively (in circumstances where the same requirements were considered to be unnecessary for the safe and secure operation of the system prior to the commencement of the Code) unless there is adequate justification for the application of those requirements to the relevant Code participants after taking into account the cost to those Code participants of complying with those requirements.

Issues arising from the draft determination

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

C14.4 The derogations relating to technical requirements of generators and NSPs in Victoria must end on or before 31 December 2002.

C14.5 The derogations relating to technical requirements of generators in South Australia must end on or before 31 December 2002.

C14.6 Exemptions of South Australian generators from the Code must be included in Chapter 9, prior to commencement of the NEM.

Discussion at the pre-decision conference focussed on the technical requirements currently specified in Chapter 5 of the Code. Some interested parties suggest that Chapter 5 could in fact be reduced to a range of common minimum standards, thus enabling existing generators to operate in the market and comply with Chapter 5 of the Code. Where facilities have extra technical features these could be compensated for through the provision of ancillary service payments, and in this manner the level of reliability of the power system need not be compromised by lower technical standards in the Code.

The incumbent Victorian generators focus on the difficulty that generators and NSPs will have in complying with the Code's present technical standards, especially if the derogations from these standards end by 2002. They state that no power station meets the Code requirements but system security is functioning adequately. Further they contend that the cost of upgrading existing facilities is prohibitively high compared to the cost of meeting the technical requirements when commissioning new facilities. Moreover the derogations were rigorously tested before inclusion. They also state the original Code approach of requiring new entrants to meet modern technical standards could now be questioned as not all new generation will be small or cogeneration (eg large gas turbines scheduled in Queensland).

Two solutions were proposed:

- NECA should revise the Code to state absolute minimum requirements and establish ground rules for safe grid connection with few or no derogations. The focus would be on removing all barriers to entry based on modern technology standards and differing technology types. Higher requirements should be met through ancillary services contracts or markets. It was noted that there may be some difficulty in agreeing to an acceptable minimum standard; or

- Accept permanent derogations for existing generators and attempt to improve standards over time, in particular reviewing the technical requirements to see what is absolutely necessary for new operators.

Delta states that they feel the Code should only specify common performance requirements and that some characteristics only need to be available from a few suppliers to achieve system security measures which should be dealt with as ancillary services. The ancillary services working group concluded that most ancillary services can be sourced competitively (eg frequency and voltage control) or through a regulated price mechanism. The Victorian Government considers that a more efficient alternative to removing the technical derogations is to require incumbent generators to contribute to the additional costs incurred by new entrants in complying with the redefined standards.

The BCA/EWG and ACA raise the concern that new generators (eg cogeneration) will have to face a higher level of standards than incumbents. While seeing the logic of minimum standards they were concerned that the cost of system standards will be borne by new entrants and users. Further new entrants may bear the cost of rectifying the system. They also flag the issue of competitive neutrality between public and private participants in industry.

Hazelwood agrees that new entrants to the market should not have to bear the costs of rectifying the system.

TransGrid cautions against lowering standards to a lowest common denominator, because a reduction to only match present capacities could jeopardise system security. TransGrid and the BCA/EWG support a thorough review of Chapter 5.

Commission considerations

The Commission accepts the general view put forward at the pre-decision conference that the need for technical derogations arises because of the construction of Chapter 5 of the Code. Several participants state that none of the incumbent generators can meet the Code requirements, yet the system currently operates at a high level of safety and reliability. The effect of the derogations is to reduce the technical standards to those currently in operation.

However, the purpose of Chapter 9 is to allow for derogations which are of a transitional nature in order to enable Code participants to effect an orderly transition to the provisions 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 grand fathering existing facilities but requiring new facilities to meet Code requirements. Consequently, the Commission will be seeking to have these derogations cease after a short transitional period, thereby allowing the facility owners (ie 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 such facilities 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. In addition, the extent of any entry barriers will be minimised where an effective market for the supply of ancillary services creates a financial incentive for generators and others to meet the various Code requirements.

The Commission's concerns are supported by a number of interested parties. After considering the discussion at the pre-decision conference, it appears that a review of the technical standards required for entry to the market may be appropriate to resolve the issue of the appropriate level of technical standards. However, the Commission will let the market participants and the applicants determine if and when such a review takes place.

The Commission is also concerned that these technical derogations do not appear to have a sunset clause and that incumbents in Victoria and South Australia 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 clauses 9.7.5 and 9.7.6 include an end date, no later than 31 December 2002.

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 conditions of authorisation the Commission notes that an alternative process for derogations exists and recommended that if the technical derogations currently set out in Chapter 9 of the Code need to be extended then the processes outlined in clause 8.4 of the Code should be followed.

Similar arguments apply to the South Australian derogations. The Commission notes that in clause 9.28(b) and (d) South Australia reserved the right to apply to NEMMCO for further exemptions from the Code. These provisions are explicitly available to all market participants under Chapter 8 of the Code. For the avoidance of doubt the Commission's authorisation does not apply to any further exemptions South Australia may seek in accordance with the Code processes.

The Commission also recommends that the following points be considered for inclusion in the network technical requirements principles:

- that existing plant is required to upgrade to meet the Code requirements where economically feasible; and

- if it is not economically feasible for existing plant to upgrade then new entrants are not required to compensate for the derogations.

Conditions of authorisation

C14.4 The Code must be amended to provide that the derogations in Chapter 9 of the Code, relating to technical requirements of generators and NSPs in Victoria must end on or before 31 December 2002.

C14.5 The Code must be amended to provide that the derogations in Schedule 9D1 of Chapter 9 of the Code, relating to generators in South Australia must end on or before 31 December 2002.

14.5 Network connection and planning

Victoria (clause 9.7)

Victorian transmission and distribution networks are to be regulated by the Regulator–General until 31 December 2000. If a dispute arises in respect of certain issues, it must be dealt with in accordance with the conditions of the relevant transmission or distribution licence, not under Chapter 8.

From 1 January 2001, the Regulator–General will regulate distribution connection and planning. Any question as to the fairness and reasonableness of an offer to connect to a Victorian distribution network is to be decided by the Regulator–General. If a dispute arises in respect of any connection issues in relation to Victorian distribution networks, then that dispute must be resolved in accordance with procedures specified by the Regulator–General (clause 8.2 does not apply).

New South Wales (clause 9.15)

If a dispute arises in respect of transmission network connection and is not resolved, the matter must be referred to IPART for arbitration and Part 4A of the *IPART Act 1992* will apply rather than the procedures in Chapter 8. This will not apply to a dispute which arises on or after 1 July 1999.

If a dispute arises in respect of distribution network connection and is not covered by the appeal procedures set out in section 96 of the *Electricity Supply Act 1995* and is not resolved, then the matter must be referred to IPART for arbitration. If the dispute arises on or before 31 December 2000, then Part 4A of the *IPART Act 1992* will apply to the dispute to the exclusion of the dispute resolution procedures of Chapter 8. If the dispute arises on or after 1 January 2001, then the matter will be referred to IPART to act as the Adviser and, if IPART thinks it appropriate, to also act as the DRP under the dispute resolution procedures in Chapter 8. If the appeal procedures set out in section 96 of the *Electricity Supply Act 1995* apply to a dispute of the type referred to, those procedures will apply to the exclusion of the dispute resolution procedures set out in Chapter 8.

ACT (clause 9.22)

If the ACT Minister has nominated arrangements set out in any ACT legislation or New South Wales legislation as those to be followed in the event of a transmission network connection dispute and a dispute arises, the parties must comply with the procedures specified by that legislation to the exclusion of clause 8.2. This does not apply to a dispute arising on or after 1 July 1999.

If a dispute arises in respect of distribution network connection, the parties must comply with the procedures set out in any ACT legislation relating to distribution access. If dispute and/or appeal procedures set out in the legislation apply to a dispute, those procedures apply to the exclusion of the dispute resolution procedures in clause 8.2. This does not apply to disputes arising on or after 31 December 2000.

Issues for the Commission

Derogating from the dispute resolution and enforcement provisions in Chapter 8 of the Code may create a barrier to entry.

What the interested parties say

Delta Electricity submits that with regard to derogations for network connection, the important principle should be that adequate information is made available to participants to ensure fair contracts can be put in place.

What the applicants say

The applicants state that Victoria believes it is inappropriate to divide responsibility for regulating the price of distribution services and the terms and conditions on which access to distribution services must be provided between State regulators and the national regulator. The reasons stated are that the regulated entity may 'play off' the two regulators; the pricing regime will make assumptions about efficiency gains a distribution business may achieve; and numerous customers and transactions are involved which will raise issues that are not of a magnitude which is appropriate for a national regulator to resolve. Thus, the transitional arrangements provide for the Regulator–General to continue to regulate distribution access as well as distribution pricing from 1 January 2001, but applying the terms of Chapter 5 and not a Victorian specific access regime.

In respect of New South Wales, the applicants anticipate that many of the disputes which will arise will relate to distribution network service pricing, and accordingly the New South Wales Government considers it appropriate for the body which will regulate distribution network pricing in New South Wales, namely IPART, to be responsible for determining connection and access disputes in New South Wales.

For the ACT, the applicants submit that its size and the fact that its distribution networks exist as an integral part of the interconnected New South Wales system, mean that the ACT jurisdictional regulator should probably adopt practices consistent with other jurisdictions so as to reduce costs and facilitate adequate comparisons.

In respect of the transitional arrangement for augmentation, the applicants state that where augmentation work has already been taken into account in calculating PNV's charges under the Tariff Order, the procedures that apply to augmentation under the Code do not apply.

Commission considerations

The provisions relating to dispute resolution are not subject to the administrative provisions in Chapter 8. This may have implications for the administration of the Code firstly, because the enforcement provisions do not apply and secondly, because the dispute resolution provisions do not apply and this may adversely affect potential new entrants.

The Commission is concerned, particularly given its analysis with respect to the dispute resolution processes in Chapter 8, that any derogation from the Code's dispute resolution processes may discourage entry to the NEM because an intending participant may be excluded from using fair and efficient processes if it cannot negotiate a satisfactory agreement with NSPs. Therefore, the Commission recommends that the relevant jurisdictional dispute resolution processes set out that they can be accessed by intending participants.

Under clause 9.7.4, in respect of connection to the distribution networks, the Victorian Regulator continues to be responsible for regulation, including dispute resolution procedures for what appears to be an indefinite period of time. It would be preferable if they were to eventually comply with the Code for the sake of uniformity between the jurisdictions.

The applicants must also satisfy the Commission that there are no conflicts arising out of having IPART act as the Adviser and DRP which might prejudice IPART's ability to implement a fair and efficient dispute resolution process.

The Commission considers that the ACT provisions do not provide enough detail and requests that NECA provide more specific information.

Conditions of authorisation

C14.6 Clause 9.22 must be amended to specify which dispute resolution arrangements will apply in the ACT.

C14.7 Clause 9.15 must be amended so that where any conflicts arise out of having IPART act as the Adviser and DRP which might prejudice IPART's ability to implement a fair and efficient dispute resolution process, an alternative Adviser or DRP is selected.

14.6 Network pricing

Victoria (clause 9.8)

Regulation of transmission and distribution network pricing is to be carried out by the Regulator–General under the arrangements set out in the EI Act, the *Office of the Regulator–General Act 1994* and the Tariff Order up until the end of 2000.

If a dispute arises in relation to transmission service pricing that is regulated under these regulatory arrangements, then that dispute must be resolved in accordance with these arrangements and Chapter 8 of the Code does not apply. After 31 December 2000, in determining transmission service pricing in respect of a Victorian transmission network, the Commission must ensure that each Distributor is to have the benefit or burden of an equalisation adjustment for each fiscal year. [109] This phases out by 30 June 2020 (see table in clause 9.8.4).

[109] Distributor has the meaning given to it under the Tariff Order.

If a dispute arises in relation to distribution service pricing then that dispute must be resolved in accordance with the above regulatory arrangements and Parts D and E of Chapter 6 and Chapter 8 of the Code do not apply. From 1 January 2001, any national guidelines for distribution service pricing as they apply to distribution networks in Victoria and guidelines and rules formulated by the Regulator–General must be consistent with clause 5.10 of the Tariff Order. In addition, the arrangements outlined in Parts D and E of Chapter 6 will be applied subject to clause 5.10 of the Tariff Order. The value of sunk assets determined under clause 6.10.3(e)(5)(B) must be consistent with clause 5.10(b) of the Tariff Order. In regulating distribution service pricing, the Regulator–General must specify explicit price capping as the form of economic regulation to be applied in accordance with clause 5.10.5(b) and must apply with clause 5.10 of the Tariff Order.

The Victorian transmission pricing derogations for the period 1 January 2001 to 31 December 2007 are dealt with separately in section 14.2.

New South Wales (clause 9.16)

The Jurisdictional Regulator for New South Wales is IPART or any other person or body appointed for this purpose. Specific interim regulatory arrangements (see clause 9.16.2) for the regulation of transmission network service pricing in New South Wales will cease to apply on and from 1 July 1999. Related to this, clause 9.18.1 inserts a new definition for 'transmission network' for New South Wales. This states that the transmission network will be 'declared by the Minister for Energy under section 93 of the *Electricity Supply Act*'. This clause ceases to have effect on and from 1 July 1999.

Specific interim regulatory arrangements apply to distribution network service pricing (see clause 9.16.3(a)). In the event that no determination is made by IPART to cover the period after 30 June 1999, distribution network service pricing for New South Wales distribution networks will be regulated under and in accordance with Parts D and E of Chapter 6 by IPART. This derogation will cease to apply on and from 1 January 2001.

ACT (clause 9.23)

The Jurisdictional Regulator for the ACT is the Energy and Water Charges Commission or any other person or body appointed for this purpose. The interim regulatory arrangements for pricing of transmission services for any transmission network situated in the ACT are those under the ACT *Energy and Water Act 1988* or other applicable legislation. Part B of Chapter 6 will apply from on 1 July 1999.

Distribution service pricing for the period prior to 31 December 2000 will be regulated by the Energy and Water Charges Commission under the ACT *Energy and Water Act 1988* or other applicable legislation, to the exclusion of Parts D and E of Chapter 6.

Issues for the Commission

These arrangements may alter the incentives on NSPs in terms of cost efficiency and for economic investment in the right locations. In addition, they may have the effect of limiting competition in and between the participating jurisdictions.

What the interested parties say

Victoria

The EUG is concerned with the proposal to apply certain equalisation adjustments put in place by the Victorian Tariff Order until 30 June 2020, albeit on a phase down basis. It notes very little information is provided in the application other than that this is to 'provide a smooth transition to fully cost reflective pricing and to recognise historic property rights.' Further, they have concerns with the proposal to derogate from certain parts of the Code beyond 2001 (no time limit is provided), including the use of price capping and of asset values set out in the Tariff Order (related to structural separation and presumably the sale of the distribution assets).

The Victorian DBs state that some of the Victorian derogations extend beyond 31 December 2000 in order to allow the provisions of the Tariff Order which relate to distribution pricing to apply beyond the transitional period. They argue that the purchase of the DBs was predicated on those arrangements, and subsequent business planning has been based on the Tariff Order having continuing effect. They believe that commercial certainty is a necessary starting point from which to work towards the NEM and altering this position would result in price shocks and other market disturbances which would retard the orderly progression to harmonised market conditions and the NEM.

The Victorian DBs highlight that the Regulator–General will have responsibility for connection disputes post–2000, yet the national regulator will have responsibility for pricing disputes post–2000. They request that the same body to be responsible for dispute resolution for both pricing and connection post–2000.

Yallourn Energy raises the issue of dealing with cross-border complaints or disputes where different regulations operate in each jurisdiction.

The EUG states that the price advantages for end users of the IPART approach to transmission regulation are apparent as they reduced the annual average revenue requirement of TransGrid by $40 million (or around 10 per cent) compared to the Code proposals.

What the applicants say

Victoria

The applicants state that the transitional period for transmission network pricing ends on 31 December 2000, consistent with the first review period under the existing Victorian Tariff Order. In addition, they say that the Victorian distributors were privatised on the basis of the pricing regulation contemplated by the Tariff Order during that first review period. The applicants state that certain equalisation adjustments put in place by the Tariff Order will continue until 30 June 2020. They say that these equalisation adjustments apply to use of system fees payable by distribution companies. The applicants argue that the purpose of the equalisation adjustments is to provide a smooth transition to fully cost reflective pricing and to recognise historic property rights.

For distribution network pricing prior to 1 January 2001, the applicants state that having the Tariff Order regulate network service pricing until the end of 2000 is consistent with the first review period under the Tariff Order. In addition, the Victorian distributors were privatised on the basis of the pricing regulation contemplated by the Tariff Order during that first review period.

The applicants argue that the use of explicit price capping is for consistency with the current Victorian arrangements in clause 5.10 of the Tariff Order which contains a number of continuing provisions which the Regulator–General is required to apply in regulating distribution network pricing after the year 2001.

New South Wales

The applicants state that New South Wales's transmission network service pricing derogation is consistent with the express provisions in Chapter 6. The New South Wales Government believes that it is logical for IPART to retain its role in distribution network pricing while there continues to be a New South Wales franchise market subject to IPART regulation as this will provide consistency in the regulatory arrangements. The applicants state that the purpose of the derogation in clause 9.18.1 is to ensure that some flexibility is maintained by the New South Wales Government with respect to the distinction between a transmission and a distribution network for regulatory purposes.

ACT

The applicants state that because the ACT's distribution networks exist as an integral part of the interconnected New South Wales system, and the small size of the ACT, the ACT Jurisdictional Regulator should adopt practices consistent with other jurisdictions so as to reduce costs and facilitate adequate comparisons. They say that the regulator will likely enter into consultancy arrangements with inter-state regulatory bodies for this purpose.

Issues arising from the draft determination

AMPOL states that, as the Commission will not regulate transmission pricing until 2002, they consider that the Commission should set a national transmission approach now so that some regulatory certainty can be established.

NECA stated that the detailed role and powers of the transmission and distribution regulators under the Code will be considered as part of the NECA review of transmission and distribution pricing arrangements.

A number of interested parties raised the issues of bypass and negotiating firm access. These issues are addressed in sections 10 and 11.

Commission considerations

As stated in section 11, the Commission is concerned with ensuring that monopoly NSPs do not have competitive advantages and that arrangements reflect efficient costs, provide appropriate locational signals, do not discriminate, provide incentives for locationally efficient investment, are flexible for individual circumstances and allow efficiency improvements to be passed to upstream and downstream firms.

The Commission is generally satisfied with the Victorian transmission network service pricing arrangements as regulation by the Regulator–General ceases at the end of 2000. The Commission accepts the imposition of an equalisation adjustment which phases out gradually until 30 June 2020 as it reflects pre-existing regulatory policies, which under pinned the privatisation of the Victoria DBs. The distribution network service pricing arrangements which operate post–2001 are also viewed as being reasonable as they apply pre-existing arrangements in the Tariff Order and are consistent with Code principles. However, the

Commission would like to be assured that clause 5.10 of the Tariff Order has a definite termination date.

The Commission accepts the New South Wales and ACT network service pricing arrangements as they are transitional, ceasing on and from 1 January 2001 at the latest.

14.7 Deemed regulated interconnector (New South Wales)

On 28 July 1997 the applicants notified the Commission of a further derogation by New South Wales, regarding a proposed interconnector between New South Wales and Queensland (clause 9.16.4). The derogation is as follows:

> The proposed *interconnector* between Armidale in New South Wales and Tarong in Queensland, to the extent that it forms part of the *power system* in New South Wales, is deemed to be a *regulated interconnector*.

Issue for the Commission

The Commission is concerned about the impact the derogation to deem Queensland — New South Wales Interconnector (QNI) to be a regulated connector may have on the overall public benefit or anti-competitive detriments of the NEM arrangements.

What the interested parties say

In response to this derogation interested parties raised two main issues.

The first is whether QNI needs to be built and if so, why the Code processes for evaluating the viability of QNI should not be used. In general, this issue is prompted by concerns about whether the beneficiaries of interconnection will pay for QNI.

The second issue is whether QNI needs to be regulated as against being entrepreneurial and as such, not subject to the revenue controls of Chapter 6 of the Code. For instance, while the EUG recognises QNI's role in facilitating Queensland's participation in the national market, it does not agree that it needs to be a regulated interconnector.

To a large extent, the questioning of the need to regulate QNI has been prompted by the nature of the regulatory mechanism in the Code which effectively underwrites the investment and allocates costs to end use customers. The EUG questions whether PowerLink and TransGrid consulted with interested parties on generation and demand side alternatives (as will be required in the future by the Code) and complains that a cost-benefit analysis of the project had been withheld from the public. The EUG states that:

> "... the market should be given the opportunity to provide the least cost option for addressing Queensland power constraints through a competitive process without resorting to Code derogations."

In a similar vein, the ACA has concerns about the lack of market signals to justify the capital outlays and the impact QNI will have on contestable, alternative options such as embedded generation or demand side responses.

Hazelwood Power argues that it is essential that the same degree of rigour contemplated by the Code is applied to QNI. In particular, Hazelwood Power argues that it is important that the granting of the derogation does not effectively sidestep the proposals of clause 3.12.3

(changing the status of an unregulated interconnector), including the Code consultation procedures. Clause 3.12.3(a)(2) sets out that the person requesting that the unregulated interconnector be included in the transmission network being regulated under the Code provisions must demonstrate to NECA that such inclusion is in the interests of those Code participants or other person who will bear the cost of increased transmission charges.

Capral argues that the derogation ‘effectively prevents independent assessment of whether the investment is justified and in the interests of customers in both States.’ Capral indicates that this concern is aggravated by the fact that:

> “... since the National Code imposes almost all network charges on customers (rather than on generators), customers in New South Wales will bear the cost of the New South Wales share of the cost of interconnection when it is the New South Wales generators who gain the benefits.”

This concern is echoed by other participants, such as Australian Paper which argues that it does not:

> “... support the concept that the electricity users in New South Wales should subsidise the New South Wales generators’ ability to sell their product into Queensland. If the interconnect is regulated (rolled into the TransGrid rate base) then transmission cost for all New South Wales users will be increased with no benefit to New South Wales electricity users.”

Australian Paper argues that in order to send the appropriate locational signals and while electricity flows are north-wards, the New South Wales generators should pay for the New South Wales costs of the interconnect whilst Queensland’s interconnect costs should be rolled into PowerLink costs and passed on to Queensland consumers. Similar concerns were voiced by Boral which notes that in Victoria, it is proposed that a separate tariff be used for a gas interconnector.

The Tasmanian Government indicates general support for the proposal.

What the applicants say

The applicants state that the proposal to interconnect follows a feasibility study undertaken by TransGrid and PowerLink Queensland (the owners of the transmission assets in the respective states). The study concludes that QNI is a cost effective method of avoiding construction of generation capacity, will reduce fuel costs and will increase competition in the NEM. The applicants state that a review by London Economics [110] of the proponents’ study supports the feasibility study and concludes that there are net benefits to New South Wales and Queensland and all states in the NEM including:

- avoided cost of new generation plant;
- fuel cost savings;
- shared ancillary services; and

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[110] The report by London Economics, *Independent review of the economic costs and benefits of interconnection of the Queensland and New South Wales electricity grids, August 1997,* is available on request from the Commission or can be accessed at *http://accc.gov.au/contact/electric.htm*.

- increased competition in the NEM.

The applicants do not directly address the public benefits that may flow from the decision to deem the interconnector a *regulated interconnector*.

Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

C14.9 Clause 9.16.4 must be deleted.

This condition has the effect of disallowing the derogation to deem QNI to be a regulated interconnector.

At the pre-decision conference a number of matters regarding the derogation were raised, including:

- the adequacy of the processes leading to the planning of QNI;
- the timing of the proposal;
- whether QNI is needed; and
- if needed, whether QNI should be regulated.

On the issue of process, the New South Wales Government representative stated that the QNI process has been underway for seven years and is supported by numerous studies. The most recent study by London Economics was undertaken because NEMMCO was not in a position to implement the Code consultation procedures. Deeming QNI as a regulated interconnector would resolve the issue of revenue uncertainty for the investors (PowerLink & TransGrid). The New South Wales Government representative noted the concerns of a number of participants, emphasising that QNI will still be subject to the risks and discretions of the regulatory process as set out in the Code. Its benefits are estimated at $600-700 million in avoided cost for generation, reserve and fuel, and these benefits will be shared by New South Wales and Queensland. Transmission prices may increase by around 3.6 per cent in New South Wales. Spot prices not likely to increase. The London Economics study concludes that alternatives are complementary to QNI but are not viable substitutes.

The Queensland Electricity Reform Unit (QERU) made a number of points regarding alternative electricity supply options. QERU stated that Queensland requires additional generation because the State is facing four per cent annual demand growth. When the Eastlink proposal failed, generation tenders were sought and twenty bids were examined (coal, gas, hydro, cogeneration) out of which came three generators (744MW) at Yabulu, Oakey & Mt Stuart. The maximum amount of Demand Side Management proposed was 40MW. Further, QERU stated there has been an extensive process of consultations, briefings, and inputs which have been more detailed than the Code requirements. Options of multiple corridors were examined. QERU also noted that increasing the size of QNI involves a major cost increase (from $450 million for 1000MW to $1.1 billion for 2000MW). Studies show minimal technical impact on Victoria and South Australia.

At the pre-decision conference, BCA/EWG stressed the importance of full information disclosure and public scrutiny of the arguments supporting QNI. The Institute of Public

Affairs advocated that the issue should be referred to customers, not governments, to ensure the right incentive drivers are in place and so the cost of QNI and its approval is borne by those who will benefit from it.

Ampol argued at the pre-decision conference that the London Economics figures are not convincing (eg differing treatment of public and private capital risks) and that, while the benefits of QNI go to generators, the costs will be carried by customers through a higher revenue cap. Ampol recommended that QNI should not be permitted to be a regulated interconnector, but should only go ahead if price differences between the two regions were sufficient to support an entrepreneurial interconnector.

Additional written submissions

Following the pre-decision conference a number of submissions were received by the Commission, elaborating and emphasising positions put at the pre-decision conference.

In their submission Integral Energy states that an interconnector should only be deemed regulated if the parties can demonstrate a net customer benefit, otherwise DBs face increased TUOS charges (which will be passed on to their customers) and generators benefit from assets without contributing to the cost of the asset.

Ampol states in their submission that, as an informed first tranche customer in New South Wales, they were not consulted regarding QNI, they did not see any calls for submissions and do not believe that QNI can be justified under the Code processes. Further they note that the benefits of QNI flow to generators and the costs are imposed upon customers.

The EUG argues that due process has not been undertaken, and alternatives to QNI have not been adequately assessed. It notes that costs to customers have been flagged at 3.6 per cent and seven per cent of TUOS in New South Wales and Queensland respectively, although any benefits are theoretical and dependent on modelling and assumptions.

Similarly, the ACA states that they do not consider due process has been undertaken as insufficient information has been provided to adversely affected parties (electricity consumers in New South Wales and Queensland and potential proponents of generation in Queensland), and insufficient time has been given to consider the London Economics report. Further, it states that the London Economics report may be flawed in its assessment of benefits (and in the underlying assumptions). The ACA also states that deeming QNI to be regulated raises competitive neutrality issues, as it will compete with local generation but the owners receive a regulated return on the asset and pass through the risk to consumers. The ACA also contends that generators should pay for the cost of the asset, rather than New South Wales customers.

A further submission from the ACA was received in response to consultations held by the ERTF. The ACA’s submission raises questions regarding the validity of the modelling undertaken by London Economics, including assumptions regarding pool price levels and long run marginal costs of generation. It states that the cursory treatment of demand side alternatives is unwarranted as the tendering process was not conducive to demand side response. The ACA also questions the quantified savings of reserve plant and the time pressures claimed by New South Wales. It also states that it has had no chance to discuss alternatives to TransGrid/PowerLink being the builder/owner/operators of QNI and raises the issue of whether some of this work is being made contestable.

Boral made two submissions regarding the QNI derogation. It contends that including QNI in the asset base of the transmission NSPs is an inappropriate manner for costs to be recovered and will result in cross subsidisation, removal of market risk to the owners and distortion of price signals. Boral also contends that the proponents of QNI have not presented any new information to the Commission which enables the Commission to alter the position it has taken in the draft determination. Boral has argued that by accepting this derogation the Commission would in essence be taking on the roles of both the IRPC and NEMMCO. Boral suggests that delaying the decision on the regulated status of QNI would enable the NECA review to be finalised and the outcome of the review, if the incidence of TUOS charges is altered, may allay the concerns of some customers.

In their submission BCA/EWG raise concerns regarding:

- the incidence of the costs and benefits of QNI;
- the length of time required to generate sufficient benefits to exceed the costs;
- the magnitude of the increase in transmission costs;
- the lack of robustness of economic and other assumptions;
- a tendency to try to overcome problems with the market trading system through building QNI to enlarge the market; and
- the independence of London Economics who act as primary consultants to the Queensland Government on electricity matters.

The BCA/EWG notes that previous interconnectors have been subject to much more extensive public scrutiny.

Westcoast Energy presents a number of criticisms of the London Economics report in their submission, including many of the assumptions underlying the results and also raise concerns regarding the need for the derogation, and the effects on TUOS charges.

In its submission, Ecogen Energy argues that interconnectors should be treated as non-regulated traders, buying and selling between regions, and earning economic rents according to the power flows across QNI. Such a process will allow an interconnector to compete on an equal basis with generation and demand side options, rather than shifting the risk onto customers as is presently the case if an interconnector is regulated.

SMHEA and SHT state that the process for establishing non-regulated interconnectors should be expedited by the Commission imposing a condition of authorisation setting a deadline for finalisation of a process to be included in the Code.

The proponent's submission provides further detail on the processes followed, benefits from QNI, the need for the derogation and a justification for having a regulated interconnector. The information presented is discussed further in the Commission considerations section below.

Commission considerations

The concerns raised by interested parties include:

- process and timing;
- whether QNI is needed; and
- if QNI is needed, whether QNI should be regulated.

The Commission has considered each of these matters in making its assessment.

Processes

The proponents argue that they are under no obligation to follow Code processes, as the Code does not yet take effect, and the processes they have followed reflect those that are valid at this time. However, the proponents have also stated that they consider the QNI proposal will meet the requirements set out in clause 5.6.6 of the Code.

As noted in the draft determination, the Commission considers that in the transition period prior to NEM commencement, to the extent possible, the processes followed by the proponents should reflect the Code processes.

The Commission is concerned that the studies supporting the building of QNI have been confidential, and that the London Economics review of the original work was only made publicly available from 22 August 1997. This concern is reflected by interested parties, from outside of the respective State governments or owners of the transmission assets, who stated they had not been given an opportunity to review or critique the findings. Many submissions received since the pre-decision conference also state that the time given to consider the derogation and supporting documents has been inadequate.

The Commission notes that the QNI process in its various configurations, has been a long process, commencing some seven years ago and that the proponents of QNI have undertaken substantial consultations. The difficulties have arisen because the constituents that are required to be consulted under the Code processes are somewhat different to those that have been consulted as part of the processes ‘normally’ undertaken in development proposals of this nature. In response to the Commission's draft determination the proponents did undertake some further consultation with interested parties who had indicated concerns regarding QNI. However, it remains apparent that interested parties still have concerns regarding the consultation process and that the latest round of consultations is very late in the decision making process and unlikely to impact upon decisions made by the proponents.

Nevertheless, the Commission considers that interested parties have now had sufficient time to consider and comment upon the derogation.

Timing

The issue of the timing of QNI was raised in several submissions, with many interested parties claiming that the time lines set out by the proponents still allow ample time for Code processes to be undertaken, or for the Code requirements regarding unregulated interconnectors to be developed. Further, by not allowing the derogation at this time, interested parties argues that decisions regarding the regulated status of QNI would be made after the finalisation of the NECA review of transmission pricing, the outcome of which may alleviate concerns regarding that customers or generators would pay for QNI through TUOS charges.

The proponents of QNI indicate that in order to have QNI operational by 2001, they need the economic basis for QNI to be established by early 1998. The underlying economics will form part of the Environment Impact Statement (EIS) process which must be completed by November 1998, in order for contracts to be put in place and construction to commence. The proponents state that in order for the construction of QNI to be complete by 2001, they cannot suffer the delay of waiting for NEMMCO and the IRPC to be established and gain legal jurisdiction over the decision regarding regulation of QNI.

QERU has further added that the construction of the interconnector by 2001 is seen by the NCC as a necessary condition for payment of competition payments to Queensland. Lack of compliance with this timetable would be considered evidence of a lack of completion of a National Competition Policy commitment. QERU suggests that the NCC views the interconnector as of national significance. QERU also states that any delay to commencing QNI will mean that the interconnector will not be ready when required, forcing Queensland to build generation capacity. QERU states that in such an event the interconnector would then be delayed for a lengthy period of time as any generation investment is likely to be baseload plant and this has implications for the market reform strategy being pursued in Queensland and could result in many of the benefits of reform not being achieved.

Based on the information provided by NEMMCO and the proponents of QNI the Commission accepts that the proponents of QNI must derogate to have QNI deemed a regulated interconnector. The Commission accepts the statement from the proponents that a decision on whether or not QNI is to be a regulated interconnector is required early in 1998 to feed into the EIS process. Delaying the assessment of QNI until after market commencement would delay the process beyond what the proponents have indicated is manageable.

In their supplementary submission the proponents claim that a derogation from the Code processes is required because the Code processes are unavailable to the proponents of QNI. The Commission has received confirmation from NEMMCO that this is the case. NEMMCO has advised that:

- it will not be in a position to formally conduct the processes set out in clause 5.6.6 of the Code until the commencement of the NEM;
- while transitional arrangements are in place, these are fully committed and are unavailable until late January 1998. Any interim review of QNI could not be complete until May 1998; and
- the transitional arrangements are not as detailed as those set out in the Code and do not extend to the level of consultation envisaged under the Code.

NEMMCO also comment that it is aware of the processes followed for QNI including:

- the determination of the costs and technical capabilities of various interconnection options;
- the economic evaluation of interconnection options versus alternative generation expansion programs; and
- consultations with interested parties.

NEMMCO concludes that "this evaluation process followed by the New South Wales and Queensland jurisdictions is consistent with the process that NEMMCO would propose to undertake".

Is QNI necessary

Several submissions from interested parties raise concerns regarding the assessment of the benefits stemming from QNI, as put forward in the London Economics report. The Commission is not in a position to determine the veracity or otherwise of the details of the London Economics report. Moreover, as noted above, the Commission is not performing the tasks of either the IRPC or NEMMCO, and it does not consider that its role in this authorisation is to assess the costs or benefits of building QNI. However, the Commission, as regulator of transmission networks in New South Wales and Queensland from 1999 onwards, will have to form a view on the value of the assets of the owners of QNI.

Should QNI be regulated

The Commission sees considerable merit in the Code requirements as they set down clear processes and criteria for establishing regulated interconnectors. Moreover, these processes establish an ex-ante discipline on the investment decisions for regulated interconnectors which will generally compete with contestable generation and demand side alternatives. These processes are important as the risks faced by a regulated interconnector, with a stipulated return, are likely to be considerably different to the risks faced by a firm operating in a competitive market. However, this does not mean that there are no ex-post disciplines on an investment decision for regulated interconnector as the regulator still has the ability to optimise a network's assets.

Boral, the EUG, Westcoast Energy, BCA/EWG, ACA, Ampol, and the incumbent New South Wales DNSPs raise the issue of the incidence of the costs of QNI, compared to the probable incidence of benefits — ie New South Wales end use consumers will pay for QNI assets through their TUOS charges, whilst New South Wales generators and Queensland customers will benefit from a larger market and lower prices, respectively.

The proponents note that the incidence of benefits is not clear cut, and it is expected that there will be considerable flows across QNI in both directions. Therefore, they reject the contention that the benefits will be limited to Queensland customers, and expect that there will be benefits to New South Wales customers as well.

The Commission accepts the proponents view that flows may be north or south, depending upon market conditions in both states. With regard to the incidence of TUOS the Commission notes that the effect of this derogation is not to guarantee the proponents of QNI the income stream necessary to make the investment viable. By deeming the QNI asset to be regulated they will be subject to the same methodology that applies to all regulated transmission assets.

As discussed in the Commission's assessment of the NEM Access Code, the Commission has considerable concerns about the efficiency signals associated with the Code's network pricing arrangements. As evidenced by participants' concerns, these efficiency signals will be lacking even more in the period prior to any inter-regional transfers of network charges (see clause 6.3.4 of the Code). The Commission has signalled that it expects the NECA review to consider the incidence of TUOS charges. Changes to the incidence of TUOS charges and commencement of inter-regional transfers will address many of the interested parties concerns regarding whether the beneficiaries of QNI will be required to fund the investment.

Further, the Commission, as regulator of transmission assets in New South Wales from 1999, will have responsibility for assessing the asset base of TransGrid, including assets associated with QNI.

The regulated income stream that TransGrid earns will depend upon the Commission's assessment of the optimal value of those assets. As regulator the Commission may form a view that the value of the QNI assets is considerably less than the costs of construction.

The Commission considers that the regulatory process, in particular the process of an independent regulator optimising the assets of the transmission network, provides sufficient protection to all market participants regarding the allocation of network costs. The Commission notes the valid concerns of many industry participants but stresses that deeming QNI to be regulated does not offer TransGrid or PowerLink a risk free return on the asset, it simply ensures that the assets are regulated on the same basis as other transmission assets.

Commission decision

The Commission considers that there are public benefits arising from the development of QNI. These benefits include competition benefits arising from an increased efficiency in the use of reserve plant; a possible reduction in the degree of market power on New South Wales generators; greater customer choice and efficiency benefits arising from an integrated approach to ancillary services in the NEM.

Further to these general benefits, the derogation to have QNI deemed a regulated interconnector will have benefits in the form of providing the proponents with certainty regarding the cost recovery methodology that will apply to the assets (although not certainty regarding income stream), and benefits of avoiding transaction costs associated with any duplication of processes.

The general anti-competitive detriments claimed by interested parties relate to the incidence of costs and benefits and the decision making processes followed. The Commission contends that the first of these issues will be dealt with in the context of optimising the asset bases of the proponents within the regulatory framework to be established by the NECA review.

With regard to the issue of process the Commission stated in its draft determination that it has concerns over the processes followed by the proponents of QNI and indicated a preference for the Code processes to be followed to the extent possible. However, the Commission has accepted NEMMCO's statement that it is not in a position to undertake these normal processes within the required decision making timelines. Furthermore, NEMMCO has indicated that the processes adopted for QNI are largely consistent with what it would have undertaken, had the transitional arrangements applied to QNI.

Therefore the Commission has decided not to impose any conditions of authorisation regarding this derogation. This gives the proponents of QNI sufficient certainty regarding the regulatory framework of QNI to proceed with the EIS process.

The Commission has not based its decision upon the economic merits or otherwise of QNI or alternatives to QNI. It has noted both the London Economics report and the proponents submission regarding the benefits arising from QNI and has also noted the deficiencies in both those documents as put forward by interested parties. Whether or not QNI is an efficient investment will be a matter which the Commission will revisit when the time comes to optimise the asset bases of TransGrid and PowerLink. The Commission notes that it is a real possibility that the asset bases of the transmission companies could be substantially devalued as part of the optimisation process if QNI proves not to be an efficient interconnector.

14.8 Additional jurisdictional derogations

14.8.1 Customer contestability

Clause 2.3.1(d) of the Code requires each jurisdiction to nominate the persons that may register as a customer under the Code. Both Victoria (clause 9.4.1) and New South Wales (clause 9.12.2) set out that if a person holds a retail licence or is a non-franchise customer they satisfy the requirements. For both jurisdictions, from 1 January 2001 all persons may register. South Australia sets out the requirements which must be satisfied in the regulations to the *Electricity Act 1996* (clause 9.26.2).

Issues for the Commission

The timetable for eligibility of customers may be considered to be exclusionary provisions, exclusive dealing provisions, or provisions having the purpose of effect of substantially lessening competition, and may breach the TPA.

What the interested parties say

The EUG believes that to facilitate a contestable NEM, all jurisdictions should set and align their contestability thresholds as quickly as possible, and preferably aim for full contestability by 2000.

What the applicants say

The applicants state that the timetable providing for all customers in Victoria to become contestable by 2001 ensures that there is progressive and comprehensive deregulation of the retail market. They note that over time all New South Wales businesses and individual consumers will be eligible to purchase electricity either directly through the wholesale pool or from a retailer of choice.

In South Australia's case, the applicants say that all customers with peak demands above 5MW will be eligible to register as customers upon commencement of the NEM in South Australia. They note that the South Australian Government is currently finalising its timetable for opening up the South Australian market beyond this threshold. They argue that the timetable developed by the South Australian Government will ensure that there is a realistic, orderly and manageable transition to customer participation in the NEM and increased contestability for supply of electricity to customers.

Commission considerations

The Commission notes that all customers in Victoria and New South Wales become contestable by 1 January 2001. It accepts that this provides some stability and certainty to the market during the transitional period. The Commission recommends the South Australian customer contestability timetable align with other participating jurisdictions by the year 2001, ie. full contestability by this time.

14.8.2 Traders

Victoria, New South Wales and South Australia have provisions dealing with traders (see clauses 9.4.3–9.4.4, 9.12.1 and 9.12.3, and 9.26.1 respectively). These clauses deem the traders to be entitled to register as either customers in respect of electricity supplied or generators in respect of particular generating units, in order to meet pre-existing contractual arrangements. The arrangements cease upon the expiry or termination of the contracts.

In Victoria and New South Wales, the traders do not have to comply with the Code in certain circumstances and NECA has to report quarterly on non-compliance.

Issues for the Commission

Meeting the provisions of existing contracts through Code rules could have the effect of distorting the market and reducing the public benefits of competition and may be exclusionary or exclusive dealing provisions. These derogations may also provide a competitive advantage to incumbent generators or NEM participants over potential new entrants.

What the interested parties say

The EUG has concerns about the impact of these derogations, but notes that the provisions relate to existing contracts and are the subject of vesting arrangements. It says it would be concerned if any additional electricity supplies that might be required by these operations were also made the subject of derogations or if other restrictions on market participation were included. It also assumes that these contracts can be renegotiated by mutual agreement of the parties and would support such a process in order to remove these derogations sooner. The EUG notes and supports the requirement for NECA to be notified of any acts of Code non-compliance arising from these derogations and for it to report on impacts on market efficiency (which should be extended to include any impacts on competition).

Alcoa has concerns relating to section 91AC(1)(c) of the *Electricity Industry Act* 1993 (Victoria) (EI Act) which applies to the Portland and Point Henry Smelters. Its view is that section 91AC(1)(c) applies solely to existing contractual arrangements between the Smelters and the SECV. However, it is concerned that section 91AC(1)(c) of the EI Act may be capable of a wider interpretation which would extend its application to future additional power requirements. Alcoa argues that the section should only apply to the extent of its existing contractual relationship with the SECV. It states that in a competitive market, it should have the right to contract for any additional power requirements with any legitimate market participant. It contends that, since no derogation has been sought for section 91AC(1)(c), the legislation must either be determined not to undermine the competition principles of the national grid or an exemption must otherwise be sought.

The Tasmanian Government is broadly supportive of the changes to the Victorian arrangements.

What the applicants say

For Victoria, the applicants state that the Smelter Agreements contain a number of provisions that relate to the technical performance required of the power stations which were negotiated before the relevant chapters of the Code were prepared. The applicants say that there are protections in place to ensure that the provision relieving the SECV of its obligations under the Code where there is conflict with the agreements, is not abused.

With respect to the New South Wales traders, the applicants note that the derogation relates to a number of long-standing power supply agreements entered into by the then Electricity Commission of New South Wales (now known as Pacific Power). The applicants state that as part of the restructuring of the New South Wales generation sector in March 1996, Pacific Power's rights and obligations under the agreements were transferred to First State Power (now Delta Electricity) and to Macquarie Generation. Under each of these power supply agreements, the relevant generator is effectively performing the role a market customer would perform under the Code. The relevant generator has contracted directly with these end use customers to supply electricity on agreed terms.

Given the effect of these derogations, and the fact that all of these agreements were entered into before the commencement of the compulsory market arrangements embodied in the Code, the applicants consider it appropriate to continue to recognise the ongoing rights and obligations imposed on the respective generators under these agreements.

The applicants argue that these derogations do not, in any respect, impose any exclusive supply rights on the relevant supplying generator. If the end use customer is eligible to register with NEMMCO under the Code as a customer, it may choose, subject to any constraints or remedies in the relevant power supply agreement, either to:

- register as a market customer and purchase electricity through the pool for use at the premises covered by the relevant Power Supply Agreement; or
- purchase its electricity requirements from a retailer other than its local participant retailer.

In addition, the applicants note that if a generator excuses itself from complying with a relevant requirement of the Code, it will be required to notify NECA of the relevant non-compliance. In addition, NECA will be required to prepare and publish a quarterly report. They say the purpose of these provisions is to ensure that there is adequate transparency in the application of the exemptions. The applicants consider it to be in the public interest that new market arrangements should not overturn private contractual arrangements entered into in good faith well before commencement of the national market. They believe that there are no detriments that arise from these derogations.

Furthermore, they consider that with existing provisions allowing for similar arrangements under the South Australian derogations, in the interests of equity, and presenting a consistent picture of the structure of the NEM to prospective parties to such cross border leasing arrangements, the derogation is justified.

Commission considerations

The Commission is concerned with the timing of these derogations, to the extent that they extend beyond the transition period. However, the Commission accepts that pre-existing contracts will need to be adhered to. Where it is not possible to handle these contracts outside of the Code, the Commission wishes to ensure that the Code does not add further obligations nor extend the time of the agreements. This does not appear to be the case in the current draft of the Code, although the Commission notes that it does not have access to the agreements.

The Commission is of the view that the provisions dealing with compliance of the traders afford some certainty and transparency so that Code participants can see that the market is not being distorted more than is necessary to meet the terms of the contracts. The

Commission suggests that it should be explicit that the contracts are to be provided to NECA so that they can fulfil their role in the relevant clauses.

The Commission believes that, to the extent that Alcoa purchases electricity in excess of the quantities set out in the agreements, it should be able to purchase this competitively, if practical. The Commission understands that it may not be possible to know whether the contractual amount will be exceeded over the course of a year nor to distinguish between different suppliers in a given period.

The Commission notes that the Victorian Government, pursuant to its obligations under the NEM Legislation Agreement should repeal, amend or modify any Act that is inconsistent with the NEL. Further, the EI Act is listed by the Victorian Government, pursuant to its COAG obligations, as legislation which is to be the subject of major review as a matter of high priority in June 1997–June 1998.

The Commission considers that the effect of section 91AC(1)(c) of the EI Act will not alter the balance between anti-competitive detriment and public benefit such that it warrants further Commission consideration.

The Commission notes the comments of the BCA/EWG regarding the recasting of the Loy Yang B (LYB) Uplift Payment as a Smelter Reduction Amount (SRA)and that, in line with previous comments by Treasurer Stockdale, the smelter levy should be paid for by taxpayers, not electricity consumers. However, the Commission accepts that there are benefits in including LYB in the market arrangements as much as possible and that there is no greater detriment arising out of the new arrangements.

14.8.3 Loss factors

Victoria (clauses 9.5.1 and 9.5.2), New South Wales (clauses 9.13.1 and 9.13.2) and the A.C.T. (clauses 9.21.1 and 9.21.2) each have similar transitional arrangements in place relating to the determination of loss factors for each jurisdiction. [111]

Issue for the Commission

These provisions could amount to an arrangement that has the purpose, or is likely to have the effect, of fixing or controlling the price for electricity through the wholesale market.

To the extent that the national arrangements in clause 3.6 provide efficient signals, this derogation may be anti-competitive in that it results in price distortions between final consumers, impacting on market efficiency and locational signals.

Also, the provisions could have the effect of advantaging Code participants in one jurisdiction over Code participants in another jurisdiction, affecting inter-state trade and competition.

What the interested parties say

The EUG acknowledges the applicants' submission that these arrangements should have no impact on aggregate loss factors and that there are procedures for review and comment by

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[111] The Code deals with network losses in clause 3.6 and this is analysed in section 8.3 above. See also Code clause 3.6.2 and 3.6.3.

NECA. Nevertheless, the EUG argues that this proposal will introduce power usage and pricing distortions into the customer end of the NEM and may raise prices to some customers. Moreover, the EUG contends that, given the work going on to harmonise loss factors under NEM1, consideration should be given to extending this to customer loss factors in the jurisdictions.

The EUG also states that privatisation of distributors in Victoria may also introduce sovereign risk considerations.

What the applicants say

For all jurisdictions, the applicants state that these derogations are designed to avoid price shocks to rural customers.

The applicants do not believe that the provisions will have significant competition or identifiable overall cost implications. As these provisions do not affect the loss factors applied to market generators, they have no impact upon the prices received by those generators or competitive merit order dispatch. Similarly, since the loss factors applied to customers, and hence the price or energy at their respective connection points, apply irrespective of who purchases the electricity from NEMMCO, the loss factors will have no impact on competition between retailers or the relative merits of wholesale and retail purchasing.

Commission considerations

As discussed in section 8.3 above, accurate calculation of losses provides economically efficient locational price signals to ensure the most economic outcome in terms of location of generation and load on the grid. Losses are also important in ensuring that new investment is appropriate and that the right balance is achieved between investment in generation, demand side measures and/or the transmission network.

The Commission considers that any differences between jurisdictions in determining transmission intra-regional losses could distort inter-state trade. In addition, alternative methods of determining both transmission intra-regional losses and distribution losses could create price distortions between consumers within each region, thus reducing competition. At present the jurisdictions cross-subsidise from urban to rural on the basis of losses and this derogation extends that practice.

The Commission notes that the derogations do not apply to generators or registered scheduled loads in respect of transmission and distribution networks. [112] This means that the jurisdictional loss factors will apply to load for non-contestable customers, ie. customers paying regulated tariffs.

While noting the applicants' argument that this avoids price shocks to rural customers during the transitional period, the Commission believes that, to the extent that losses represent a CSO, as a general principle, a transparent CSO payment is a far better mechanism to achieve equity goals.

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[112] Scheduled load is defined in the Glossary. It is the Commission's understanding that scheduled loads are price-sensitive loads, ie. whether a customer consumes or not depends on the market price.

Nevertheless, given that regulated tariffs exist and the derogations for New South Wales, Victoria and the ACT cease by 2001, the Commission considers that the clauses can stand as transitional arrangements in order to maintain market stability. The Commission's consideration of the South Australian loss derogations for the period 2002–2010 is contained in section 14.3, above.

The Commission is also concerned with the appointment of the governmental body which is to calculate the intra-regional transmission loss factors and distribution loss factors. If this body is part of the machinery of government, there may be pressure for it to calculate loss factors which comply with government policy in a non-transparent way. The Commission recommends to all jurisdictions that an independent regulator should be appointed to calculate loss factors.

The Commission considers that the provision for review by NECA (in the case of distribution loss factors) and the requirement for aggregate outcomes to be the same (in respect of transmission intra-regional loss factors) should ensure that there are no adverse consequences upon inter-state trade.

14.8.4 Victorian Industrial Relations Force Majeure and White Hole Money

The Victorian derogations in clauses 9.5.4–9.5.7 and Schedules 9A1.1–9A1.3 deal with Industrial Relations Force Majeure (IRFM) Events and White Hole Money. The IRFM provisions impose a cap on the pool price during periods of industrial dispute beyond the control of the market as a whole and allow for compensation to generators during IRFM Periods. If a market generator is entitled to be paid an IRFM Uplift payment then the SECV is liable to pay NEMMCO the share attributable to franchise demand; and the portion attributable to the non-franchise load is paid by market customers which are financially responsible for one or more connection points in Victoria (Schedule 9A1.1 clause 7). There are provisions for auditing IRFM Uplift amounts and values of demand in Victoria.

In addition to other participant fees, Victorian market participants must pay fees to recover any material incremental costs incurred by NEMMCO in the development of systems for, and the administration of, the IRFM Uplift and in calculating, billing, collecting and recovering any amount for the IRFM Uplift.

The White Hole Money clauses provide for payments where there are counter-price flows of electricity into Victoria during periods when an administered price cap has been invoked in that State due to an IRFM Event. [113] In the case of counter-price flows of electricity into Victoria, NEMMCO would be liable to pay out to generators in another region more than it is entitled to receive from customers in Victoria. Each Victorian market customer for that trading interval is liable to pay NEMMCO an amount based on its share of total Victorian demand multiplied by the amount of White Hole Money.

NEMMCO is to report on an 'IRFM Event' and must review the operation of the IRFM derogations within six months of market commencement, having regard to the financial effects of an IRFM Event being confined to Victoria, any risks or costs that NEMMCO is

[113] Under normal conditions, electricity will flow from a low price to a high price region. A counter-price flow will occur when electricity is transmitted from a high price region into a low price region.

exposed to as a consequence of the IRFM derogations, and the release of information regarding IRFM Events to all market participants.

The provisions are to terminate on 31 December 2000.

Issues for the Commission

The IRFM provisions could constitute arrangements that have the purpose or may have the effect of substantially lessening competition as they may confer a competitive advantage upon Victorian generators and could distort wholesale trade.

What the interested parties say

In relation to IRFM Events, the EUG suggests that the Commission should explore more fully the costs of this derogation. It notes that these provisions do not apply to cogeneration or to inter-state generators.

EnergyAustralia states that the criteria by which NEMMCO can intervene in the market must be clearly defined. It does not agree that issues such as site-specific industrial actions warrant market suspension and feels that many of these events should be handled by the individual organisations concerned. Moreover, it contends that poor management should not be rewarded.

With respect to White Hole Money, the Victorian DBs state that under Schedule 9A1.1 the White Hole Money Uplift should be treated on the same basis as the IRFM Uplift. They believe that it is inappropriate to expect the retailers to pay part of the uplift attributable to the franchise market where it is an amount that the retailers cannot hedge.

What the applicants say

The applicants state that the purpose of the IRFM arrangements is to prevent or minimise the pass-through to franchise customers of the financial effect of certain kinds of labour disputes which affect the industry. They argue that, during the transition to a fully competitive retail market, the IRFM provisions help stabilise electricity prices for franchise customers in the event of industrial action.

Issues arising from the draft determination

The Victorian Government note in their submission that the provisions in the Code relating to IRFM will end on or before 31 December 2000. CitiPower submits that the IRFM provisions must end no earlier than 31 December 2000 as the vesting contracts are dependent on this provision.

Commission considerations

The provisions dealing with IRFM Events and White Hole Money are substantially the same as those in NEM1 Stage 1 and more detailed analysis by the Commission can be found in the NEM1 Stage 1 Working Paper published in March 1997.

In summary, the Commission is not convinced that protecting Victorian generators from industrial disputes has significant public benefit, as it reduces commercial risk to generators and does not assist in resolving disputes or ensuring supply of electricity. In addition, the arrangements may dull economic signals for the development of a market in suitable risk management instruments, investment in reserve capacity and demand side responses. The provisions may also alter the risk allocation associated with contracts between participants located in Victoria and those in other regions, and Victorian generators do not have to factor into dispatch prices the costs of managing industrial relations risks.

The Commission is concerned that the White Hole Money Uplift may discourage new entrants on the customer side of the wholesale market, but if NEMMCO was to cover the loss, then participant fees would need to be increased. This may raise the barriers to entry for all market participants, not just those who sell into and buy out of the pool during the shortfall interval. On the demand side, market customers could be discouraged from importing electricity during shortfall intervals as it may be difficult for them to pass on the costs.

Also, under clause 3.16.4(e), STFM contracts and IRH contracts in existence prior to the declaration of market suspension will continue to be enforceable, which may mean that the IRFM Event is not confined to Victoria.

As a result of these concerns, the Commission requests that NEMMCO develop a workable mechanism for confining the impacts of IRFM Events to Victoria and bring this to the Commission for authorisation.

The Commission notes that the IRFM provisions mean that there is the necessity to have a clause setting the Victorian region to be the State of Victoria until the IRFM provisions terminate. However, the Commission considers that as the provisions terminate by the year 2000 this can be allowed to stand until then.

The Commission is not convinced that the public benefit of protecting the market from price shocks due to IRFM Events outweighs any anti-competitive detriment. However, as the market in risk instruments is still immature and the arrangements are transitional, the Commission will allow the provisions to stand at this time. The Commission would not be accommodating towards similar provisions being submitted in the future by Victoria or other jurisdictions.

The Commission recommends that NEMMCO give serious consideration to whether the provisions could be deleted when it undertakes the six month review of the operation of the clauses.

14.8.5 Smelter Levy

In order to accommodate the contractual arrangements existing between the Loy Yang B Power Station (LYB) and the SECV, a levy was imposed upon participants in the Victorian market (LYB Levy). This levy compensated the SECV trader for the difference in spot price received from the pool and the contractual price to be paid to the owners of the LYB, in respect of electricity sold by the SECV trader under the power supply agreements.

The Victorian Government has now sold its remaining share in LYB, and as part of this process has also unwound various contractual arrangements, including the power supply agreements. LYB is now a market participant, in the same manner as other generators. In order to facilitate these new arrangements the Victorian Government has recast the LYB levy as a SRA (clause 9.5.8), enabling it to recoup revenues which otherwise would have been lost to the government.

Issues for the Commission

The imposition of the SRA may have the effect of decreasing public benefits by discouraging entry into the Victorian sector of the NEM, as it represents an additional cost on Victorian market customers.

What the interested parties say

The EUG opposes this derogation, which provides a cross-subsidy to the smelters from other customers, as it has a significant impact in distorting end-use prices and market competition, and therefore creates a bad precedent. The EUG acknowledges that the arrangements which gave rise to the levy stem from decisions made by a previous government, and that a mechanism needs to be found to deal with this. It argues that the arrangements with the smelters should be financed out of the State Budget rather than by electricity customers who were not party to the original decisions, but must now bear the cost.

Australian Paper argues that the SRA is a tax which, if required, should be legislated rather than recovered by ‘back door means’ such as through a derogation to the Code. It states that there is no logic which supports the imposition of a tax on electricity users which is more properly worn as a charge to general revenue.

Hazelwood Power notes that customers are being expected to continue to support the smelter electricity price, while the market is denied access to the interruptability provisions of the smelter contract, except for ancillary services. Hazelwood argues that the absence of an opportunity for the market to access demand side response from the smelter appears to be inconsistent with the subsidy being paid by consumers.

Alcoa believes that the derogation is inappropriate and should not be included in the final version of the Code. Indeed, Alcoa argues that the Smelter Levy should not be permitted to apply to transmission charges in Victoria. It claims that the levy makes an ‘uncompetitive transmission system even more uncompetitive’. Alcoa states that including any costs which are not genuinely related to transmission, in the transmission cost structure, represents an impost which Victorian consumers can ill-afford. It adds that any costs which the Victorian Government identifies with the smelter power contracts should be a part of the State’s overall financial outlays.

What the applicants say

The applicants claim the changes outlined above have no substantive effect on the initial submission since the LYB levy has been recast as the Smelter Levy and LYB replaces the dedicated SECV LYB trader as a market participant. They note that the restructuring of the LYB arrangements should result in an increase in competition as a result of termination of the uneconomic power supply agreements, the addition of LYB as a direct participant in the market and regulation of LYB on the same basis as the regulation of other generators.

Issues arising from the draft determination

Boral Energy expresses its concern that the New South Wales Government levy, of $5.50/MWh applying to all energy consumed by contestable customers, is viewed in the same light as the SRA, especially as the level of the levy did not reduce in order to take account of the unwinding of the SECV-LYB arrangements.

EUG expresses their concern over the Victorian proposal to levy customers in that State an amount that compensates for the current agreement between the Victorian Government and the smelters of Portland and Point Henry. This arrangement ties the price of electricity in Victoria to the price of aluminium and lasts until 2016.

BCA/EWG argues that, in line with previous comments by Treasurer Stockdale, the smelter levy should be paid for by taxpayers, not electricity customers.

Commission considerations

The Commission accepts the applicants' contention regarding the unbundling of the LYB power supply arrangements, and the general benefit that should arise from the inclusion of the LYB power station as a market generator, rather than the previous LYB trader arrangements.

The Commission is concerned about the effect that the continued application of the LYB levy in the form of the SRA will have on entry to the NEM, for participants intending to trade in Victoria. The application of the SRA to market customers means that the cost of the restructuring of the power supply agreements is born by the market customers and, to the extent that they can pass through the levy, electricity consumers. However, the alternative of the Victorian Government financing the new arrangements through debt may be more anti-competitive than that proposed.

The Commission is also concerned about the equity of the levy being imposed, to the extent that it doesn't reflect the actual losses of the smelter trader, and the asymmetry in its application whereby the smelter trader will not refund to market customers amounts of the SRA collected that are greater than the actual losses incurred. However, the Commission does not consider the arrangements will materially affect the balance of public benefit and anti-competitive detriment.

14.8.6 System security

Victoria (clause 9.6.1) and New South Wales (clause 9.14.1) have transitional arrangements in place dealing with regional specific power system operating procedures (for the purposes of clause 4.10.1(b)). [114] The system operating procedures in place in each jurisdiction at market commencement are the regional specific power system operating procedures that apply in respect of their transmission networks. Provision is made for review of these procedures.

Issues for the Commission

The system security transitional arrangements may have the potential to decrease the public benefit derived from the operation of a competitive NEM.

What the interested parties say

The EUG states that it has no *prima facie* objection to the New South Wales derogation provided it is shown that the New South Wales Operating Procedures are not anti-competitive and are consistent with the National Electricity Code and the market objectives. The EUG

[114] The New South Wales arrangements were amended on 21 April 1997.

argues that as there is no attempt to show this, further information should be sought from the applicants.

The consultant's view

Western Power argues that clauses 9.6.1 and 9.14.1 are reasonable. It adds that these derogations would appear to be in accordance with the intent of clause 4.10.1(b) of the Code. Western Power states that these provisions do not limit the provisions of the Code relating to the review, updating and amendment of the operating procedures, therefore, there is scope for the procedures to be revised.

Western Power is of the view that the participating jurisdictions should be aiming for uniform operating procedures where possible.

Western Power adds that the approach adopted with respect to Victoria's nomenclature standards is reasonable.

What the applicants say

The applicants argue that, for transitional purposes, existing system operating procedures and nomenclature standards should remain in place after the commencement date.

The applicants state the Network Operating Standards (New South Wales Standards) have the same general effect as the schedules to Chapter 5 of the Code. They claim that, in the event that there is any discrepancy between the Code and the New South Wales Standards, the latter shall prevail.

The applicants further state that, in addition to the New South Wales Standards, New South Wales will adopt the System Operating Procedures (New South Wales Procedures) after consultation with NEMMCO. The New South Wales Procedures and the New South Wales Standards will form the regional specific power system operating procedures as contemplated by the Code. The applicants contend that the New South Wales Procedures are designed to ensure that the interconnected New South Wales network is operated in a safe and reliable manner. In particular, the New South Wales Procedures are designed to recognise the need to minimise the risks of damage to persons and property, whilst maintaining a high degree of reliability in the ability of the interconnected New South Wales power system to deliver electricity to end use consumers in a useable form.

They argue to the extent that any arrangements contained in the New South Wales Standards and the New South Wales Procedures substantially lessen competition (and they do not concede that the New South Wales Standards and New South Wales Procedures have any such effect), it should be recognised that their provisions are designed to ensure that the interconnected New South Wales network operates in a safe and reliable manner.

Commission considerations

The Commission considers that the derogations clarify the regional specific operating procedures and nomenclature standards that are to apply from market commencement in Victoria and New South Wales. Given that these procedures and standards are yet to be developed under the Code, the derogations would appear to provide for a smooth transition to the arrangements in the NEM and should ensure that there is no hiatus while a national approach under the Code is developed. The derogations would also appear to provide ample scope for the State standards to be replaced by national approaches under the Code in due course.

However, with respect to the New South Wales derogation, the Commission is concerned by the statement in the application that in the event that 'there is any discrepancy between the Code and the New South Wales Standards, the latter shall prevail'. Such a statement would appear to run counter to the objective of State operating procedures being replaced by a national approach under the Code in due course. Indeed, the Commission considers that the statement in the application is inconsistent with the derogation outlined in clause 9.14.1(b). Accordingly, the Commission is of the view that the derogation does not appear to provide scope for the New South Wales Procedures and Standards to prevail in the event of a discrepancy between them and the Code. In this event, the Commission is of the view that the derogation outlined in clause 9.14.1 is reasonable.

The Commission considers that clauses 9.6.1 and 9.14.1 may facilitate an orderly transition to the operating procedures in the NEM. Accordingly, the Commission believes that the derogations are appropriate at the current time.

14.8.7 Metering

The general metering derogations in Schedule 9F1 apply in full in the ACT and South Australia and provide a transitional period for metering to reach the standards set by the Code. Metering installations in use at market commencement must conform with the provisions of Chapter 9 of the Code (clause 7.3.4(c)).

The transitional arrangements for metering in Victoria are outlined in clause 9.9 of the Code. The arrangements apply in relation to a metering installation in use at market commencement that was required to comply with, and did comply with, the Victorian Wholesale Metering Code at market commencement. Other clauses relate to registration, metering installation components, meter accuracy requirements, security arrangements, data collection and the use of alternative technologies. All these provisions cease to have effect within five years of market commencement.

The transitional arrangements for metering in New South Wales are outlined in clause 9.17, amendments to which were received by the Commission on 21 April 1997. Several make reference to Code commencement before 10 May 1997, however, these have been ignored as the Code did not commence by that date. The New South Wales derogations provide that metering installations must comply with the provisions of Chapter 7 of the Code at the Code commencement date, unless the responsible person has been granted an extension by TransGrid.

The transitional arrangements set out in clauses 9.17.2 and 9.17.4 and amended by 9.17.3(e) apply to metering installations regardless of when the Code commences (presumably if an extension has been granted by TransGrid). These provisions deal with registration of a metering installation, accuracy and quality system requirements, all of which phase out within five years of market commencement.

Issue for the Commission

The Commission considers that the metering derogations may have the potential to decrease the public benefit derived from the operation of a competitive NEM.

The consultant's view

Western Power, argues that there are no doubt good reasons for derogations concerning differences in accuracy, conformance with Code quality and check metering during the transition period, arising from different metering regimes. It states, however, that it is difficult to see the need for other provisions to differ, such as registering metering installations with NEMMCO, metering providers to register differently and arrangements for submultiples of metering periods. Western Power adds that the six months' grace given to responsible persons in Victoria to demonstrate the accuracy of metering installations seems unnecessary and may afford entry advantages in Victoria compared to other states.

What the applicants say

The applicants do not discuss the competitive effects of the general metering derogations or of the Victorian, South Australia and ACT metering derogations in their application.

The applicants argue that the timetable for Code metering requirements operating in New South Wales under the State Code should not be effectively reset by the National Code provisions. Apart from creating a deal of confusion, the applicants argue that a resetting of the New South Wales timetable could significantly advantage certain market participants, while disadvantaging those who had been making a major effort to comply with the State Code timetable. The applicants add that market participants in New South Wales have established programs and processes to comply with State Code provisions and it is expected that they will be able to continue to meet the New South Wales timetable without having their competitive position compromised.

Commission considerations

The Commission acknowledges that the general metering derogations outlined in Schedule 9F1 of the Code 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 metering installations currently in place would not comply with the metering requirements of the Code and the shocks 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 acknowledges that there is a need for some metering derogations in the transitional period.

The Commission also recognises that these general metering derogations have quite specific time limits, with none extending for more than five years beyond NEM commencement.

The Commission by and large has few concerns with the specific Victorian and New South Wales metering derogations. The Commission notes that the Victorian derogations are very similar to the general metering derogations in the important areas of metering accuracy, testing and overall time limits. The Commission also acknowledges that the Victorian metering derogations have quite specific time limits, with none extending for more than five years beyond NEM commencement.

Accordingly, whilst acknowledging Western Power's arguments, the Commission is of the view that the anti-competitive effects of the Victorian metering derogations would appear to be slight. In addition, the Commission considers that the entry advantages accruing to responsible persons in Victoria as a result of the extra six months they have to demonstrate the accuracy of metering installations would appear to be minor. The Commission is therefore of the view that the Victorian metering derogations should be permitted.

The Commission recognises that the New South Wales metering derogations are designed such that the metering timetable in the New South Wales Code is not disrupted by the National Code provisions. Given that the New South Wales timetable would generally appear to be of a shorter timeframe than that specified in Schedule 9F1 of the Code, the Commission believes that the New South Wales metering derogations are reasonable.

The Commission notes, however, that certain clauses give TransGrid the discretion to extend the period of time in which market participants have to meet the Code's metering requirements. Clause 9.17.3(d) states, for example, that existing metering installations must meet the Code requirements by 10 May 1997 unless an extension has been granted by TransGrid, in which case the responsible person 'must ensure that the metering installation complies with the accuracy levels specified in Chapter 7 of the Code by the date specified in the extension granted by TransGrid.' Clause 9.17.1(b) would appear to give TransGrid similar power. Conceivably, such clauses give TransGrid the ability to grant an extension for as long as it so desires. Whilst appreciating the need for some discretion, the Commission considers that care needs to be taken to ensure that these clauses are not applied in order to derogate from the metering responsibilities of the Code for many years to come. Accordingly, the Commission requires that the dates of the extensions granted by TransGrid must not extend beyond 31 December 2002.

Condition of authorisation

C14.8 Clauses 9.17.1(b) and 9.17.3(d) must be amended to provide that any exemptions to the metering provisions issued by TransGrid must end on or before 31 December 2002.

15. Determination

Although the Commission considers that some of the proposed arrangements and conduct set out in the National Electricity Code would be likely to lessen competition, it also considers that there is likely to be a significant public benefit resulting from the proposed arrangements and conduct. For the reasons outlined in sections 4-14 the Commission concludes that, subject to the conditions set out below, in all the circumstances the proposed arrangements and conduct set out in 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 engaged 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.

The Commission therefore grants conditional authorisation to applications A40074; A40075 and A40076 until 31 December 2010.

The authorisation that the Commission grants is subject to the following conditions:

Conditions of authorisation

C6.1 No further provisions of the Code as currently drafted, or as amended from time to time, may be made protected provisions.

C6.2 Clause 8.3.1(a)(2) must be amended to provide that the only protected provisions of Chapter 8 are clauses 8.3.2 to 8.3.12, clause 8.4 and clause 8.5.

C6.3 Clause 3.9.4(e)(2) must be deleted.

C6.4 Clauses 3.18.1 and 2.12 must be amended to provide that:

(a) only scheduled generators can be required to pay the fees that NEMMCO allocates to the Participant Compensation Fund; and

(b) only scheduled generators who are centrally dispatched are entitled to receive compensation from the Participant Compensation Fund.

C7.1 Clause 2.2.5 must be amended to provide clearly and specifically, with regard to where, how and to whom output must be sold, the circumstances in which a generator may be classified as a non-market generator.

C7.2 Clause 2.12.3(b)(8) must be deleted.

C7.3 Clause 2.12 must be amended to provide that NEMMCO must use the Code consultation procedures in the introduction and determination of participant fees.

C7.4 Clause 2.12 must be amended to provide that:

(a) NECA's budgeted revenue requirement for each financial year, including any shortfall or excess in NECA's requirements from the previous year, is prepared and published separately from NEMMCO's budgeted revenue requirement; and

(b) a separate charge is made to Code participants to meet NECA's requirements as published.

C8.1 (a) Clause 3.3.3(a)(2) must be deleted;

(b) Clause 3.3.4(c) must be amended to provide that the date of effect of a variation in NEMMCO's determination of an acceptable credit rating is not earlier than 30 business days after the date of notification; and

(c) Clause 3.3.10 must be deleted.

C8.2 The Code must be amended to provide that NECA must, within two years of NEM commencement, conduct and complete a review of the principles for determination of regions as set out in clause 3.5.1(b).

The review must consider the adequacy and appropriateness of these principles, and of any alternative principles that might be added or substituted therefore, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C8.3 The Code must be amended to provide that NECA must, prior to 1 January 2000, conduct and complete a review of the financial impact of distribution losses. The review must consider whether marginal loss factors could be used to calculate distribution losses.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C8.4 The Code must be amended to provide that:

(a) NECA must monitor any significant price variation between the spot prices in any given trading period and the prices forecast and published by NEMMCO for that trading period;

(b) NECA must, in consultation with the Commission, determine guidelines as to what constitutes a significant price variation referred to in (a) above;

(c) NECA must prepare and issue a report every three months, or more frequently if required by the Commission. The report must:

(i) be issued no later than four weeks after the end of each three month period;

(ii) identify and review each significant price variation that has occurred since the previous report;

(iii) provide an opinion as to the reasons and/or causes of each significant price variation;

(iv) be available to members of the public on request; and

(v) be provided to the Commission.

(d) if the Commission requests NECA to provide a report to the Commission on specific market outcomes identified by the Commission, NECA must provide the report to the Commission as soon as possible but no later than four weeks from the date of the request, and must include in the report an opinion on the reasons and/or causes for the market outcomes.

C8.5 (a) Clause 3.9.4(c) must be amended to provide for the Reliability Panel to conduct yearly reviews of the value of VoLL; and

(b) Clause 3.9.4(d) must be amended to provide that changes to the value of VoLL must take effect six months after notification.

C8.6 Clause 3.9.6 must be amended to provide that the zero dispatch price during an excess generation period will apply for only one year from the commencement of the NEM.

C8.7 The Code must be amended to provide that:

(a) any money received by NEMMCO during an excess generation period must be paid to market customers;

(b) NEMMCO must develop a methodology for the calculation and prompt distribution by it of money it receives during an excess generation period, to market customers entitled to that money;

(c) NEMMCO must pay the market customers entitled to that money as soon as possible, and in accordance with that methodology; and

(d) the methodology must be incorporated into the Code.

C8.8 Clause 3.10 must be deleted.

C8.9 Clause 3.11 must be deleted.

C8.10 Clause 3.13.1(c) of the Code must be amended by substituting 'one year' for 'two years' in that clause.

C8.11 Clause 3.15.2(a) must be amended to provide for a back-up system to be used in the event that the electronic communications system fails or is unable to be accessed by some Code participants.

C8.12 Clause 3.15.9(b) must be amended to provide that:

(a) any person can access the information available to market participants, other than confidential information, provided by NEMMCO via its electronic communications system; and

(b) any charge by NEMMCO to persons for provision of access to this information must be on a cost reflective basis.

C8.13 The Code must be amended to provide that NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of clause 3.15 of the Code. The review must consider the adequacy and appropriateness of these provisions, and any alternative provisions which might be added or substituted therefore, in meeting and facilitating the Code objectives. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C8.14 Clause 3.15.10 of the Code must be amended to provide that:

(a) the market audit must be conducted by an entity that is independent of NEMMCO and the market participants;

(b) NEMMCO must either approve and endorse the market audit report and any recommendations therein by noting such approval and endorsement on the report or prepare a separate report dealing with each of the matters within the market audit report that NEMMCO does not approve or endorse; and

(c) the market audit report and any separate report by NEMMCO are to be provided to market participants and are to be made available to the public.

C9.1 The Code must be amended to provide that the reserve trader provisions, contained in clauses 3.14 and 4.8.6 of the Code, end on 30 June 2000.

C9.2 The Code must be amended to provide that NECA must conduct and complete a review of the reserve trader provisions by 30 March 2000. The review must consider the adequacy and the appropriateness of the reserve trader provisions, whether there is a need for a reserve trader in the market, whether there are any alternatives to the reserve trader provisions, whether there are any distortions to market outcomes caused by the reserve trader provisions, and whether there are any alternative provisions which might be added or substituted therefore, in meeting and facilitating the Code objectives. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C9.3 Clause 8.8.1(d) must be amended to provide that the guidelines and policies to be determined by the Reliability Panel to govern the exercise of the reserve trader function are publicly available by 30 June 1998.

C9.4 The Code must be amended to provide that NECA must conduct an annual review of NEMMCO's use of its powers of direction under clause 4.8.10. The

review must be conducted on each anniversary of NEM commencement in respect of the preceding year. The annual review must consider for each occasion on which the power was used in the preceding year, whether the exercise and manner of exercise of the power was appropriate in all the circumstances and in accordance with the Code objectives and make any recommendations considered appropriate for future exercise of the power. The report of the review is to be completed within 30 days of the end of each relevant year and is to be made available to all market participants.

C9.5 Clause 3.16.2(a) must be amended to provide that a schedule detailing the matters in clause 3.16.2(a)(1) and (2) is included in the Code.

C9.6 Clause 3.16.2(b) and 3.16.4(a) must be amended to provide that NEMMCO:

(a) must publish on the market information bulletin board, or

(b) otherwise notify without delay,

a material force majeure event or declaration of market suspension.

C9.7 Clause 3.16.4 must be amended to provide that:

(a) within 10 workings days of the suspension being resolved, NEMMCO must undertake an investigation of all aspects of that market suspension; and

(b) NEMMCO must as soon as possible provide a report on the results of the investigation, and must distribute this report to all Code participants as soon as possible and to all interested persons upon request.

C9.8 The Code must be amended to provide that NECA must, within 80 days of the third occurrence in any two year period of a force majeure event (as defined from time to time pursuant to clause 3.16.2(a)) or in any event within five years of the NEM commencement, conduct and complete a review of the provisions of clause 3.16. The review must consider the adequacy and appropriateness of the provisions, and of any alternative provisions that might be added or substituted thereof, in meeting and facilitating the Code objectives.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C9.9 Clause 5.5(f)(4) must be amended to provide that:

"compensation to be provided by the *Network Service Provider* to the *Generator* in the event that the *generating units* or group of *generating units* of the *Generator* are *constrained-off* or *constrained-on* during a *trading interval*".

C9.10 Clause 4.8.16 must be amended to provide that the results of any investigation or report in relation to operating incidents, or market suspension, must be distributed to all Code participants, and provided to interested persons on request.

C10.1 The Code must be amended to explicitly recognise the right of third parties to bypass the network.

C10.2 Clause 5.6.3(b) must be amended to provide that the representative from the nominated jurisdictional entity must not be involved with any decision of the IRPC where a conflict of interest between the commercial operation of the entity they represent and the decision of the IRPC may arise.

C10.3 Clause 5.6.5 must be amended to require the Inter-regional Planning Committee to include in its report to NEMMCO consideration of alternative strategies to network augmentation for removing or reducing network constraints.

C10.4 Clause 5.6.5 must be amended to provide that the Inter-regional Planning Committee conduct its public review processes in accordance with the Code consultation procedures.

C10.5 Clause 5.6.5(k) must be amended to provide that, in arriving at its determination under clause 5.6.5(j), NEMMCO must also consider alternatives to network augmentation including, but not limited to, alternative generation and demand side options.

C10.6 Clauses 5.7.1 and 5.7.2 must be amended to provide that reports of tests and inspections are to be made available to the Code participant whose facilities are being inspected or tested, the Code participant requiring the test or inspection, NEMMCO and any other person who may be affected by the results of the test or inspection.

C10.7 Clauses 5.7.1 and 5.7.2 must be amended to provide that NECA must annually prepare a report detailing the use of inspection and testing rights by all Code participants. The report must be completed within 30 days of each anniversary of the NEM commencement in respect of the preceding year and must be made available to all Code participants and interested persons.

C12.1 Chapter 7 must be amended before 1 July 1998, to include new metering requirements for smaller contestable customers, less than 750MWh per annum.

C12.2 Clause 7.2 must be amended to explicitly permit market participants to change Metering Providers after the meter has been installed.

C12.3 Clause 7.6.1(d) must be amended to allow NEMMCO unrestrained access to a metering installation for the purpose of testing the metering installation.

C12.4 Clause 7.6.3(d) must be amended to allow NEMMCO unrestrained access to conduct periodic random audits of metering installations.

C12.5 Clause 7.6.1(e) must be amended so that the person who tests a metering installation must make the test results available to all interested parties.

C12.6 The Code must be amended to provide that NECA must, within one year of NEM commencement, conduct and complete a review of the provisions of the Code regarding the role of responsible persons. The review must consider

possible conflicts of interest of persons performing that role, particularly where the responsible person is a market participant which takes energy from a NSP. The review must also consider any steps which might be taken to remove or ameliorate the effects of any possible conflict of interest it identifies.

The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C12.7 Chapter 7 must be amended to include guidelines relating to substitution and validation of data.

C12.8 Clause 7.13(a) must be amended to provide that agreements between NEMMCO, a market participant and the local NSP should not be permitted if they materially affect the interests of persons other than the market participant and the local NSP.

C13.1 Chapter 8 must be amended to provide that all intending participants are covered by the dispute resolution provisions.

C13.2 Clause 8.2 must be amended to provide that NECA must, within two years of NEM commencement, conduct and complete a review of clause 8.2. The review must consider the efficacy of the dispute resolution process generally and in particular what, if any, time limitation should be placed upon parties' rights to issue dispute notices or invoke the dispute resolution process. The review must be conducted in accordance with the Code consultation procedures and a copy of the report must be provided to the Commission.

C13.3 Clause 8.3.5(d)(1) must be amended to provide that both Code participants and interested parties are given an opportunity to put submissions to the Code Change Panel in respect of Code changes.

C13.4 Clause 8.5.5 must be amended to provide that operation of the Code shall not commence until the Regulations relating to sanctions referred to in clause 8.5.5(a) have been made.

C13.5 Clause 8.5.1 must be amended to provide that NECA must, using the Code consultation procedures, develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5.1. The guidelines and conditions must also set out those circumstances in which a Code participant is to bear the cost of providing the information sought by NECA, irrespective of whether a breach of the Code has occurred.

C13.6 Clause 8.6.6 must be amended to provide that NEMMCO must also develop and implement policies concerning the protection, dissemination and use of information by each of the bodies and panels established under the Code.

C13.7 The Code must be amended to provide that NECA must, using Code consultation procedures, develop and implement guidelines and conditions with respect to the exercise of its powers pursuant to clause 8.7.2(g). The guidelines and conditions must set out the matters which NECA must have regard to prior to deciding the allocation of costs of any additional compliance monitoring.

C13.8 Clause 8.7.3(b) must be amended to provide that NECA must, as soon as practicable, notify a Code participant of any decision to publish that Code participant's confidential information. Any such decision must be reviewable prior to publication in an urgent application to the National Electricity Tribunal by the Code participant who owns the confidential information.

C13.9 Clause 8.8.3 must be amended to provide that intending participants, as well as Code participants, are entitled to make submissions and attend any of the Reliability Panel's hearings.

C13.10 Clause 8.8.3 must be amended to provide that NECA, within 10 days of receiving the written report of the Reliability Panel must, subject to the applicable confidentiality provisions, make the report publicly available.

C13.11 Clause 8.8.1 must be amended to provide that, the Reliability Panel, in undertaking its review pursuant to clause 8.8.3(b) and in preparing its report, considering reliability of the power system, must limit its considerations to the transmission networks, considering other factors such as generation, demand side response and distribution networks only insofar as they affect the overall system security.

C13.12 Clause 8.9(a)(1) must be amended to provide that intending participants in the class of participants nominated by the relevant Code provisions are consulted.

C13.13 Clause 8.9(b) must be amended by adding at the end thereof:
'Any decision or determination purportedly made where the consulting party has failed to comply with clause 8.9 when required to do so, is, if made by NECA or NEMMCO, a reviewable decision and is in any case of no force or effect until the requirements of clause 8.9 have been substantially complied with.'

C14.1 Clause 9.8 must be amended to provide that the transmission pricing regulation derogations must end on or before 31 December 2002.

C14.2 Clauses 9.27.1 and 9.27.2 must be amended to specify that the derogation ends on or before 31 December 2002.

C14.3 Clause 9.29.2(j) must be amended to specify that the derogation ends on or before 31 December 2002.

C14.4 The Code must be amended to provide that the derogations in Chapter 9 of the Code, relating to technical requirements of generators and NSPs in Victoria must end on or before 31 December 2002.

C14.5 The Code must be amended to provide that the derogations in Schedule 9D1 of Chapter 9 of the Code, relating to generators in South Australia must end on or before 31 December 2002.

C14.6 Clause 9.22 must be amended to specify which dispute resolution arrangements will apply in the ACT.

C14.7 Clause 9.15 must be amended so that where any conflicts arise out of having IPART act as the Adviser and DRP which might prejudice IPART's ability to implement a fair and efficient dispute resolution process, an alternative Adviser or DRP is selected.

C14.8 Clauses 9.17.1(b) and 9.17.3(d) must be amended to provide that any exemptions to the metering provisions issued by TransGrid must end on or before 31 December 2002.

This determination is made on 10 December 1997. 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 C6.2 to C14.8, listed above, have been complied with.

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

- where the application is not withdrawn — on the day on which the Tribunal makes a determination on the review; or
- where 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 C6.2 to C14.8 have been complied with.

This determination applies to the National Electricity Code dated 24 September 1996 and subsequently amended on 21 April 1997 and 23 July 1997.

Appendix A. Consultations

New South Wales/ACT consultations

Generators

Delta Electricity

Energy Horizons/Lend Lease

Macquarie Generation

Distribution Businesses

EnergyAustralia

Great Southern Energy

Financial Investment Trader

Macquarie Bank

New South Wales Generator & Transmission Network Owner

TransGrid

Victorian consultations

Generators

Australian Cogeneration Association

Ecogen Energy

Hazelwood Power

Distribution Businesses

Powercor

Solaris Power

United Energy

Customers

Alcoa

BHP

Vested Interests

Michael Gunter

South Australian consultations

ETSA

Appendix B. Submissions

NEM Code of Conduct Authorisation and Access Undertaking:
Parties who have made submissions (as of 12 August 1997)

Access Code†

ACTEW Corporation
BHP (+ supplementary submission)
Capral Aluminium (+ supplementary submission)
Colin Taylor(+ supplementary submission)
Energy Users Group (+ 2 supplementary submissions)
Goldfields Power/Normandy Power
Hazelwood Power
Sithe Energies Australia Pty Ltd (+ supplementary submission)
TransGrid (+ supplementary submission)

Authorisation‡

Alcoa Australia (+ supplementary submission)
Australian Chamber of Manufactures
Australian Chamber of Commerce & Industry
Australian Cogeneration Association
(+ supplementary submission)
Australian Paper (+ supplementary submission)
BHP
Boral Energy (+ supplementary submission)
Business Council of Australia (+ supplementary submission)
CitiPower
Delta Electricity (+ 2 supplementary submissions)
Department of Primary Industries and Energy
Ecogen Energy
Electricity Week
EnergyAustralia
Energy Users Group
Environment Australia
Greenpeace
Michael Gunter
Hazelwood Power (+ supplementary submission)
Industry Commission
Integral Energy
Chek Ling
Macquarie Bank
Macquarie Generation
Queensland Electricity Reform Unit
National Farmers Federation
New South Wales Electricity Reform Taskforce
Northparkes Mines
Hugh R Outhred
The Partnership Group
Powercor/Eastern Energy/Solaris/United Energy CitiPower (Joint Submission)
SEQEB
Sinclair Knight Merz (Zauner)
Sinclair Knight Merz (Popple)
Snowy Mountains Hydro-electric Authority (+ supplementary submission)
South Australian Government (+ supplementary submission)
Tasmanian Government
TransGrid
Yallourn Energy
Victorian Power Exchange

† While these submissions deal primarily with Access Undertaking issues, some also include comments on authorisation issues.
‡ While these submissions deal primarily with authorisation issues, some also include comments relevant to the Access Undertaking.

Appendix C. Submissions regarding the draft determinations

Deleted:

NEM Code of Conduct Authorisation:
Parties who have made submissions in response to the draft determination and pre-decision conference (as of 27 November 1997)

Submission Author/s	Date Submitted	Submission Title
AMPOL[1]	17/9/97	Trade Practices Act 1974. Applications for Authorisation No's A40074; A4475; A40076
AMPOL[2]	2/10/97	Trade Practices Act 1974. Applications for Authorisation No's A40074; A4475; A40076
Australian Cogeneration Association (ACA)[1]	5/10/97	National Electricity Code
Australian Cogeneration Association (ACA)[2]	9/10/97	Qld and NSW Interconnector
Australian Consumers' Association	3/10/97	Australian Consumers Association Response to the Draft Determination.
Australian Paper	4/9/97	National Electricity Code: Response to the ACCC's Draft Determination
Boral Energy[1]	12/9/97	Draft Determination On Applications For Authorisation National Electricity Code And Application For Acceptance Of NEM Access Code
Boral Energy[2]	2/10/97	Re: National Electricity Market Access Code
Boral Energy[3]	8/10/97	Comments on IRH as Requested by NEMMCO
Boral Energy[4]	14/10/97	National Electricity Market Access Code — NSW Proposed Derogation
Business Council of Australia (BCA)	10/10/97	Supplementary Submission to the ACCC on the Draft Determination on the National Electricity Code
Cadia Mines	7/10/97	Re: NECA Review
CitiPower	3/10/97	National Electricity Code — Draft Determination
Consumers' Federation of Australia (CFA)	3/10/97	Letter Regarding Draft Determination
Delta Electricity[1]	12/9/97	Draft National Electricity Code Technical Derogations
Delta Electricity[2]	3/10/97	ACCC NEM code of conduct — Draft Determination Response from Delta Electricity
Eastern Energy	7/10/97	NEC: Application for Authorisation and Acceptance of Code Lodged by NEMMCO and NECA

Ecogen Energy[1]	12/9/97	Submission to ACCC Pre-decision Conference 18 & 19 Sept
Ecogen Energy[2]: Gill, Len	18/9/97	Reserve Plant Issues
Ecogen Energy[3]	29/9/97	Ecogen Submission to ACCC's NEC Draft Determination — Further Submissions Following Draft Determination Conference
Edison Mission Energy Australia Ltd (EME)	18/9/97	Comments from Edison Mission Energy Australia Ltd
Energy Brix Australia	3/10/97	Draft Determination on Applications for Authorisation of the National Electricity Code
Energy Users Group (EUG)	9/10/97	Submission on the ACCC Draft Decisions on the NEC Application for Authorisation and Industry Access Undertaking
energyAustralia	7/10/97	National Electricity Code Authorisation — Supplementary Submission
Ergon Energy	6/11/97	
Hazelwood Power[1]	12/9/97	Application for Authorisation National Electricity Code — Additional Submission Pursuant to Pre-decision Conference
Hazelwood Power[2]	3/10/97	Application for Authorisation National Electricity Code — Additional Submission Pursuant to Pre-decision Conference
Incumbent Generators — Yallourn Energy	6/10/97	Response Re: National Electricity Code Draft Determination
Incumbent NSW DNSPs — Integral	3/10/97	Response to the ACCC's Draft Determination
Incumbent Victorian Generators — Hazelwood	12/9/97	Application for Authorisation National Electricity Code
Incumbent Victorian Generators — Orr	18/9/97	Generator Derogations
Incumbent Victorian Generators — Orr	18/9/97	Prudential Counterparty Risk
Incumbent Victorian Generators — Orr	18/9/97	Settlement Residue & Inter-regional Hedging
Incumbent Victorian Generators — Orr	18/9/97	Participant Compensation Fund Payments
Incumbent Victorian Generators — Orr	18/9/97	VoLL Changes
Integral Energy	17/9/97	National Electricity Code Authorisation — Draft Determination
Loy Yang Power	3/10/97	NEC — Draft Determination
Macquarie Generation	17/9/97	National Electricity Code: Macquarie Generation Initial Response to ACCC Draft Determination

National Electricity Code Administrator (NECA)	3/10/97	Supplementary Evidence to the ACCC — Conditions of Authorisation of the National Electricity Code
National Standards Commission	11/9/97	National Standards Commission
New South Wales Treasury[1]	24/9/97	Interconnection of the NSW and Queensland Electricity Grids — Proposed Derogation to the National Code
Optima Energy	8/10/97	Submission regarding the draft determination
Outhred, Hugh	16/9/97	Temporal & Spatial Issues in a Competitive Electricity Industry & their Implications for the National Electricity Code
Pacific Power	15/10/97	TPA 1974 – Applications for Authorisation of National Electricity Code and National Electricity Market Access Code
Powercor	10/10/97	ACCC Draft Determination and Draft Authorisation of the National Electricity Code
Proponents of Qld/NSW Interconnector	10/10/97	Supplementary Information — Qld/NSW Interconnector
Queensland Treasury Corporation	5/11/97	Prudential Requirements Under the National Electricity Code
SEQEB	15/9/97	TPA 1974. National Electricity Code: Applications for Authorisation Numbers — A40074, A40075, A40076 lodged by NECA and NEMMCO — Application for Acceptance of NEM Access Code Lodged by NECA. Position Paper on Payments to Embedded Generators for Shared Network Benefits. Version 2
SMHEA[1]	11/9/97	SMHEA Response to Draft Determination on NEC
SMHEA[2]	3/10/97	SMHEA Supplementary Submission
Snowy Hydro Trading	11/9/97	Determinations on NEC
Solaris	18/9/97	ACCC National Electricity Code Draft Determination Response
South Australian Government[1]	17/9/97	Application for Authorisation: National Electricity Code Application for Acceptance: NEM Access Code
South Australian Government[2]	3/10/97	Application for Authorisation: National Electricity Code Application for Acceptance: NEM Access Code
South Australian Government[3]	12/11/97	Draft Determination on the National Electricity Code
Southern Hydro[1]	11/9/97	Response to the ACCC's Draft Determination
Southern Hydro[2]	29/9/97	Response to the ACCC's Draft Determination
TransGrid	2/10/97	Response to ACCC's Draft Determination

United Energy	6/10/97	National Electricity Code
Victorian Government	3/10/97	NEC draft Authorisation Determination — Victoria's Final Submission to the ACCC
Westcoast Energy	8/10/97	
Yallourn Energy	15/9/97	Version 1.0: ACCC Response Re: National Electricity Code Draft Determination

Appendix D. Charts

Chart 1.1: Code Change

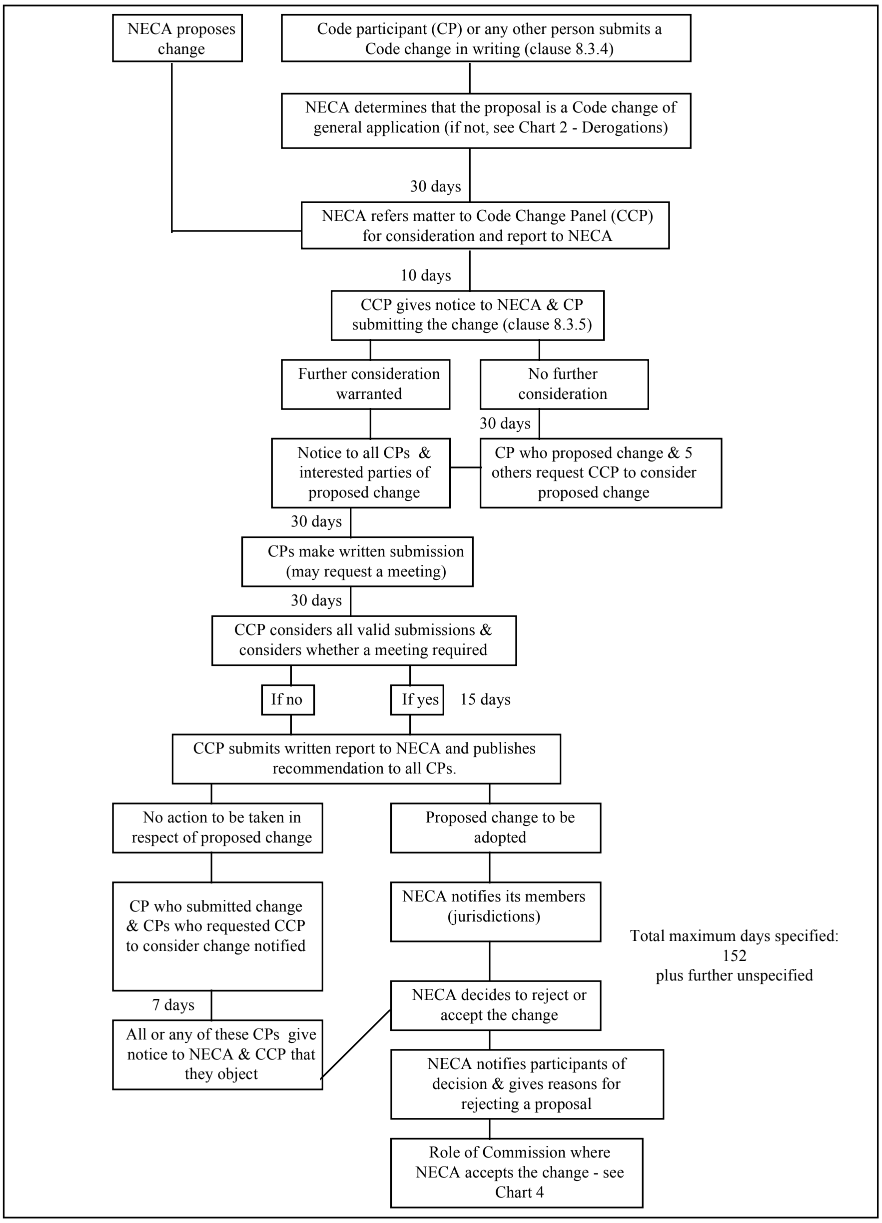
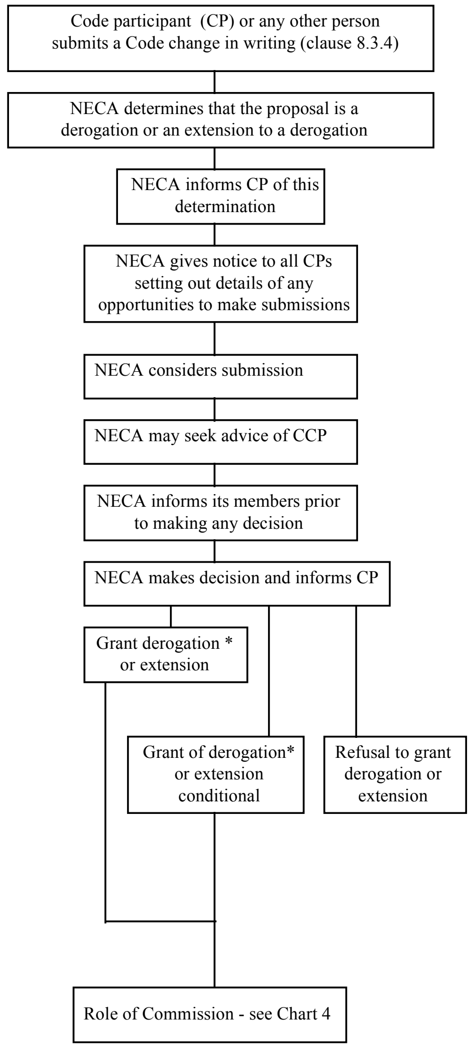


Chart 1.2: Derogations or extensions to derogations



† No time limits are specified in the Code.
* Grant of derogation or extension cannot be for an unspecified period.

Chart 1.3: Fast Track

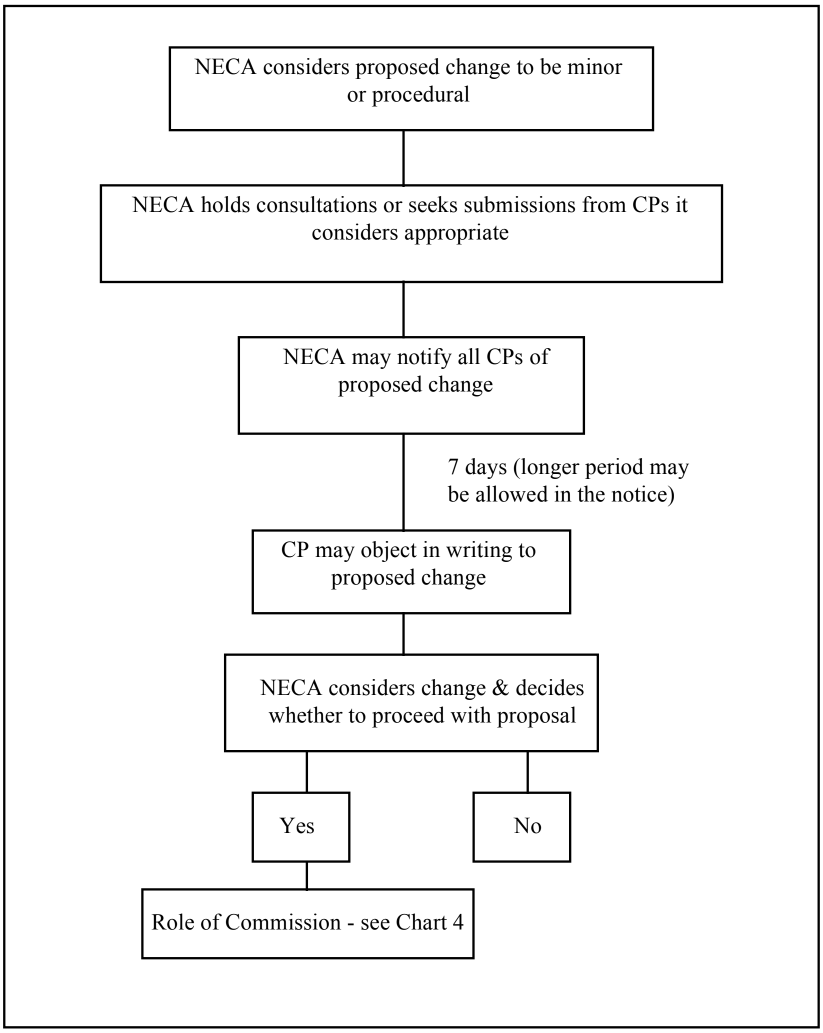


Chart 1.4: Role of the Commission

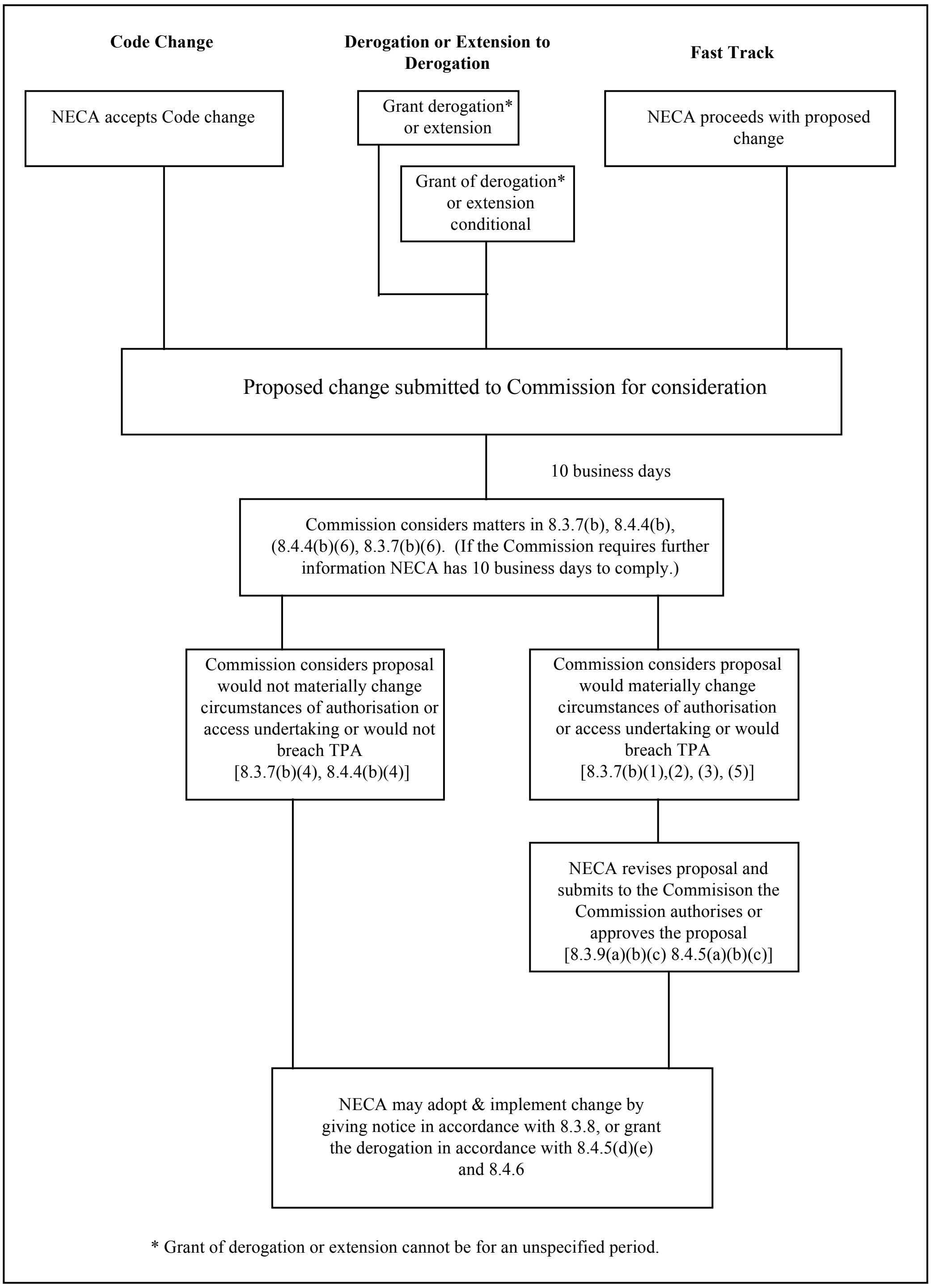


Chart 2: Reliability Panel

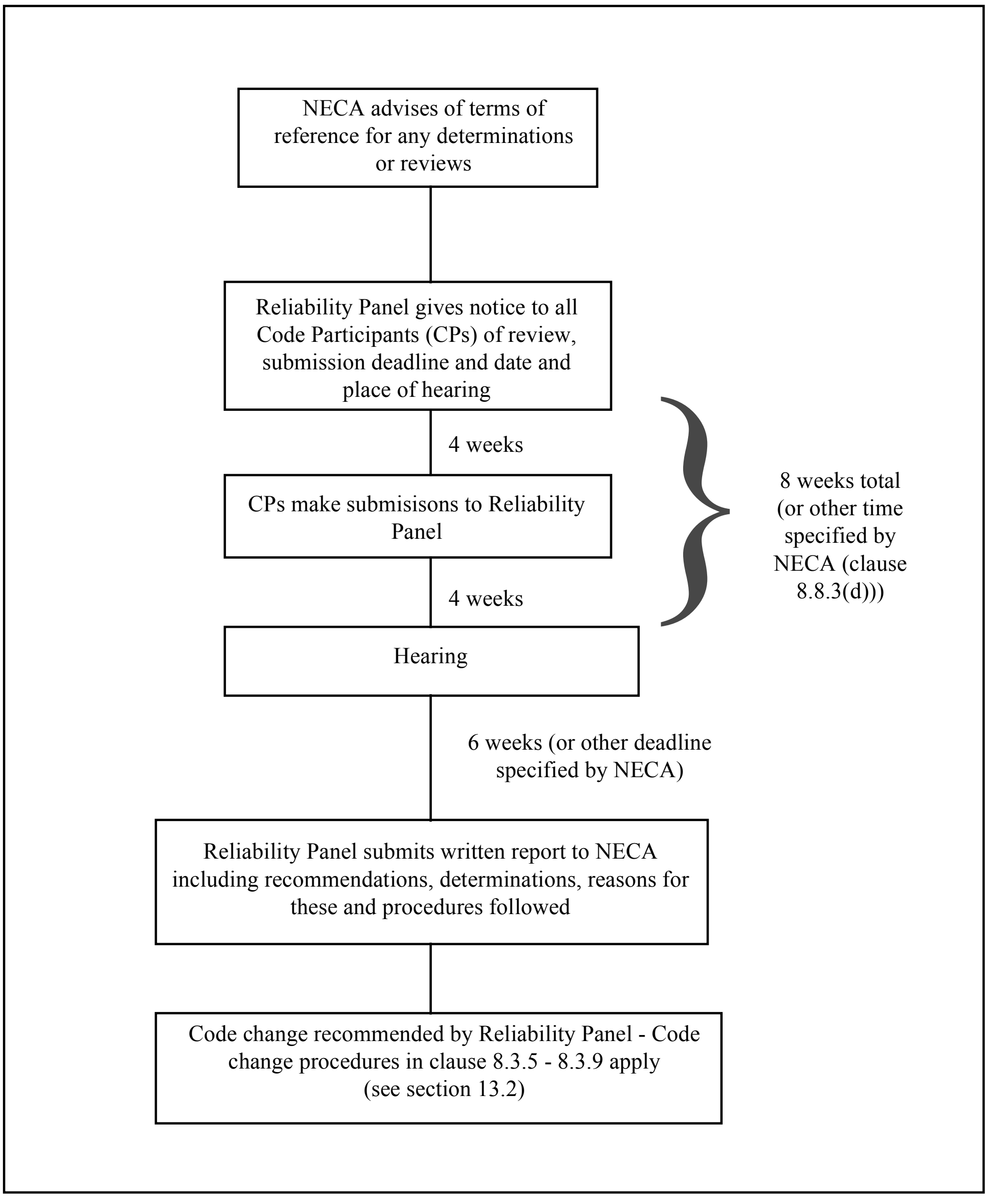


Chart 3: Code Consultation Procedures